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No. ______

IN THE

Supreme Court of the United States

OCTOBER TERM, 1986

ARKANSAS PUBLIC SERVICE COMMISSION; STATE OF ARKANSAS; ARKANSAS-MISSOURI CONGRESSIONAL DELEGATION; AND MISSOURI PUBLIC SERVICE COMMISSION,

Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondents.

APPENDIX TO PETITION FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

WALLACE L. DUNCAN*
JAMES D. PEMBROKE
J. CATHY LICHTENBERG
JANICE L. LOWER
DUNCAN, WEINBERG & MILLER, P.C.
1615 M Street, N.W.
Suite 800
Washington, D.C. 20036
(202) 467-6370

Attorneys for the Arkansas Public Service Commission

STEVE CLARK
Attorney General
MARY B. STALLCUP
Deputy Attorney General
Justice Building
Little Rock, Arkansas 72201
(501) 371-1967

Attorneys for the State of Arkansas

WILLIAM MASSEY
Office of Senator Dale Bumpers
United States Senate
Washington, D.C. 20510
(202) 224-4843

Attorney for the Arkansas-Missouri Congressional Delegation

WILLIAM C. HARRELSON
General Counsel
Missouri Public Service Commission
P.O. Box 360
Jefferson City, Missouri 65102
(314) 751-2481

Attorney for the Missouri Public Service Commission

February 1987

* *Counsel of Record*

PRESS OF BYRON S. ADAMS, WASHINGTON, D.C. (202) 347-8203

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CITY OF NEW ORLEANS, LOUISIANA,
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UNION CARBIDE CORPORATION,
OCCIDENTAL CHEMICAL CORPORATION,
ARKANSAS & MISSOURI CONGRESSIONAL DELEGATIONS,
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ARKANSAS PUBLIC SERVICE COMMISSION,
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MIDDLE SOUTH SERVICES, INC.,
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v.

FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT

Petitions for Review of Orders of the
Federal Energy Regulatory Commission

Argued March 24, 1986

Decided January 6, 1987

James P. Murphy, with whom *Michael T. Mishkin*, *James V. Selna*, *Donald T. Bliss*, and *David T. Beddow* were on the brief, for petitioner Arkansas Industries.

Carl D. Hobelman, with whom *Jerry D. Jackson*, *M. Remy Ancarrow*, and *Robert J. Glasser* were on the brief, for petitioner Arkansas Power & Light Company.

J. Cathy Lichtenberg, with whom *Wallace L. Duncan*, *James D. Pembroke*, *Janice L. Lower*, *Martin C. Rothfelder*, *William Massey*, *Steve Clark*, and *Mary B. Stallcup* were on the brief, for petitioners Arkansas Public Service Commission, *et al.*

Hiram C. Eastland, Jr., with whom *Edwin L. Pittman*, *Frank Spencer*, *John L. Maxey, II*, and *Alfred Chaplin* were on the brief, for petitioners Mississippi Public Service Commission, *et al.*

James K. Child, Jr., with whom *Paul H. Keck*, *Michael F. Healy*, *Douglas L. Beresford*, *Robert R. Nordhaus*, *Adam Wenner*, *Howard Eliot Shapiro*, and *Margaret A. Moore* were on the brief, for petitioners Mississippi Industries, *et al.*

Glenn L. Ortman, with whom *Clinton A. Vince* and *Paul E. Nordstrom* were on the brief, for petitioner City of New Orleans.

Michael R. Fontham, with whom *David B. Robinson* and *Paul L. Zimmering* were on the brief, for petitioner Louisiana Public Service Commission.

Peter C. Kissel, *Richard G. Morgan*, *Earle H. O'Donnell*, and *Robert R. Morrow* were on the brief for petitioners Occidential Chemical Corporation, *et al.*

A. Karen Hill, Attorney, Federal Energy Regulatory Commission, with whom *William H. Satterfield*, General Counsel, *Jerome M. Feit*, Solicitor, and *John N. Esler, III*, Attorney, Federal Energy Regulatory Commission, were on the brief, for respondent.

Richard M. Merriman, *Robert S. Waters*, and *James K. Mitchell* were on the brief for intervenors Middle South Services, Inc., *et al.*

William A. Chesnutt entered an appearance for intervenor Union Carbide Corporation.

Before EDWARDS and BORK, *Circuit Judges*, and WRIGHT, *Senior Circuit Judge.*

Opinion *per curiam.*

Separate opinion by *Circuit Judge* BORK, concurring in part and dissenting in part.

PER CURIAM: We consider eighteen consolidated petitions for review of two orders of the Federal Energy Regulatory Commission (FERC or the Commission).[1] In the orders under review the Commission held that the four operating companies of the Middle South Utilities (MSU) system must share the costs of MSU's investment in nuclear energy in proportion to their relative demand for energy generated by the system as a whole. The Commission implemented this scheme by reallocating responsibility for investment costs associated with the catastrophically uneconomical Grand Gulf I nuclear plant. The parties attack both the Commission's jurisdiction and the rationality of its decision. Although the Commission's allocation of nuclear investment costs is subject to reasonable dispute, we do not think such criticisms warrant reversal of FERC's orders. We therefore affirm.

I. BACKGROUND

The controversy facing the court today stems from the pattern of power generation investment cost sharing practiced by Middle South Utilities and its operating companies. In order to address fully the proper allocation of the costs of nuclear power generation among those companies, we review MSU's structure, the history of its involvement in nuclear power generation, and the record of the proceedings below.

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[1] *Middle South Energy, Inc. and Middle South Services, Inc.*, 31 FERC ¶ 61,305 (1985), and *Middle South Energy, Inc. and Middle South Services, Inc.*, 32 FERC ¶ 61,425 (1985) (opinion on rehearing).

A. *The Middle South System*

1. *Corporate structure.* Middle South Utilities, Inc. is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). 15 U.S.C. § 79 *et seq.* (1982). It owns outright four utility operating companies: Louisiana Power & Light Co. (LP&L), New Orleans Public Service, Inc. (NOPSI), Arkansas Power & Light Co. (AP&L), and Mississippi Power & Light Co. (MP&L). *See Middle South Energy, Inc.*, 26 FERC ¶ 63,044, 65,098 (1984). The operating companies sell electricity, both wholesale and retail, in the states of Louisiana, Arkansas, Missouri, and Mississippi.[2]

Although each operating company has a separate board of directors, the sole stockholder, MSU, selects each director. In addition, the various companies do have common or overlapping officers and directors. The Chairman and Chief Executive Officer (CEO) of MSU is a member of the board of each operating company and the CEOs of the operating companies are members of the board of MSU. Other MSU board members are also board members of individual operating companies. *Middle South Services, Inc.*, 30 FERC ¶ 63,030, 65,142 (Docket No. ER82-463-000) (ALJ Head).

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[2] MSU also owns a corporate services company, Middle South Services, Inc., and a fuel purchasing company, System Fuel, Inc. *See Middle South Services, Inc.*, ER82-483-000, 30 FERC ¶ 63,030, 65,141-42 (1985).

One useful way of viewing the relative size of the companies is to compare their relative shares of the system's average demand:

	Share of Total System Load
LP&L	44%
AP&L	33%
MP&L	15%
NOPSI	8%

See Middle South Energy, Inc., ER82-616-000, 26 FERC ¶ 63,044, 65,109 (1984). These figures are based on average load demand in 1982.

Transactions among the various operating companies are governed by a System Agreement. Over its history, MSU has filed three successive System Agreements—in 1951, 1973, and 1982. The Commission scrutinizes the System Agreement and modifies it when necessary. *See, e.g., Middle South Services, Inc.*, 16 FERC ¶ 61,101 (1981) (modifying the 1973 System Agreement), *aff'd*, 688 F.2d 357 (5th Cir. 1982), *cert. denied*, 460 U.S. 1082 (1983). Section 3.01 of the Agreement states the system's general goal of operating as a coherent unit:

> The purpose of this Agreement is to provide the contractual basis for the continued planning, construction, and operation of the electric generation * * * facilities of the Companies in such a manner as to achieve economies consistent with the highest practicable reliability of service * * *. This agreement also provides a basis for equalizing among the Companies any imbalance of cost associated with the construction, ownership and operation of such facilities as are used for the mutual benefit of all the Companies.

483-R. 7117, VII Joint Appendix (JA) 1569.[3] In light of this language, Administrative Law Judge (ALJ) Head found that the MSU system has sought to coordinate the addition of operating capacity by each individual operating company while achieving the greatest economies of scale.[4] As he observed:

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[3] Citations to the record in *Middle South Services, Inc.*, ER82-483-000, 30 FERC ¶ 63,030 (1985), are noted as "483-R." Citations to the record in *Middle South Energy, Inc.*, ER82-616-000, 26 FERC ¶ 63,044 (1984), are noted as "616-R."

[4] Specifically, ALJ Head found:

> Article III of the Agreement provides, *inter alia*, for planning, construction and operation of both power supply and related facilities on a coordinated basis (Section 3.02); for moving toward a new fuel base of coal and nuclear to minimize costs and reduce dependence on gas

> The System Agreements * * * clearly permit and encourage, for efficiency, reliability and other economies of scale, that the individual companies from time to time build larger facilities than are necessary to meet their own native load, to benefit all the generating companies by having lower costs and greater reliability. * * *

30 FERC at 65,142.

All three System Agreements have assigned the task of coordinating the planning of new generating capacity to a systemwide Operating Committee.[5] The CEO of each operating company designates one member of the committee, as does MSU. The members representing the operating companies control 80% of the votes on the committee, apportioned according to each individual company's share of the system's investment in generating capacity. The representative of MSU votes the remaining 20%. Under Section 5.04 of the System Agreement, the Operating Committee can now take action on the basis of a bare majority. 483-R. 7129, VII JA 1581.

2. *Investment cost sharing.* As ALJ Liebman noted, the MSU system planning approach to new generating capacity inevitably results in certain operating companies having less generating capacity than do others for varying periods of time. *See* 26 FERC at 65,098 (Docket No.

> and oil (Section 3.03); for a long-term goal of each company having a proportionate share of coal and nuclear units available to serve its customers * * *; and for joint planning on a system-wide basis for construction and operation of major facilities to achieve economies of scale associated with construction and operation of larger generating units * * * (Section 3.08).

30 FERC at 65,122.

[5] Thus under § 5.06(c) of the 1982 System Agreement the Operating Committee is responsible for, *inter alia*, determining the amount of reserve capacity on the system and requiring the installation of that capacity. *See* 483-R. 7130, VII JA 1582.

ER82-616-000). If a company does not have enough capacity to meet the needs of its consumers, the deficient operating company can always draw on the excess capacity of the other companies on the system.[6] This system also benefits those companies that have built more capacity than necessary to meet current demand. Such companies generally find willing buyers of their surplus among the other companies on the system.[7]

Under the system planning approach, it is inevitable that an operating company will, from time to time, provide a proportionate share of the system's investment in generating capacity that is more or less than its proportionate demand for the system's energy. If a company's share of the system's generating *capacity* is greater than its share of the *energy* actually generated and distributed by the system as a whole, the company is deemed to be "long." If the company's share of the system's generating capacity is *less* than its percentage of the system's energy, the company is deemed "short." 26 FERC at 65,099.[8]

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[6] For example, in the 1960's and 1970's AP&L almost never had enough capacity to service its native load, and frequently drew on LP&L's capacity to make up the deficiency. 26 FERC at 65,098-99.

[7] All energy on the system is dispatched from a central office in Pine Bluff, Arkansas. 30 FERC at 65,142. The System Agreement establishes a schedule called MSS-3 setting rates for the purchase of energy from the system pool. When a company needs energy it is billed for the lowest cost energy available in the pool. Companies owning the capacity that generates such low cost energy have first claim to that energy. 483-R. 7151, VII JA 1603. When a company needs more energy than its native capacity can produce it therefore must stand in line behind the other companies for access to the relatively cheapest kilowatts.

[8] The terms "long" and "short" do *not* refer to a company's ability to provide enough energy to meet its customers' requirements. Instead, they reflect a comparison of the share of system capacity contributed by a particular company with the share of the system's energy utilized by that company. It is entirely possible that a company could be "short" and

Since 1951 the MSU system has sought to iron out the inequities that would otherwise result where some companies were long while other companies were short through a system of "equalization payments." Prior to 1973 each "short" company made a payment to the "long" companies based on a fixed dollar amount per kilowatt of capacity that the company was short.[9] In 1973 the System Agreement was amended to provide for capacity equalization payments calculated under the "participation unit" formula, a formula that based payments on the ownership costs of the latest unit constructed by the "long" company.[10] *See id.*; *see also* 30 FERC at 65,122-23.

Importantly, this new system did *not* call for equalization payments based on the relative number of *dollars* each company had invested in generating capacity. Instead, the relative number of *kilowatts* of generating capacity owned by each company formed the basis for the payments. Because kilowatts can vary in cost, the system potentially perpetuated the operating companies' relatively unequal investment in generating capacity.

For over twenty-five years, however, the system largely avoided this potential inequity. Notwithstanding its limitations, the equalization payment approach managed to produce the *effect* of roughly equalizing the cost of investing in new capacity from the 1950's through the 1970's. During the years in which the 1951 System Agreement was in force the cost of creating such capacity was relatively uniform and relatively constant. *See* 616-R. 1332-

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still have more than enough capacity to meet its own needs. 26 FERC at 65,099.

[9] Specifically, the 1951 System Agreement provided for a monthly payment of $1.10 per kilowatt by which a company was "short." *See* 483-R. 7398, VII JA 1786.

[10] This approach also provided for the "short" company receiving an entitlement to a proportionate share of the energy generated by the "participation unit." 26 FERC at 65,099.

33, I JA 140-41; 30 FERC at 65,168.[11] As a consequence, the System Agreement's allocation of equalization payments based on a constant dollar per kilowatt of short capacity served to equalize investment costs. Although in the 1970's the cost of new units began to exceed that of older facilities by a substantial margin, the 1973 System Agreement balanced this development by basing equalization payments on the costs of the newest (and more expensive) units of the "long" companies. 26 FERC at 65,100.[12]

3. *The shift to nuclear energy and its consequences.* In the 1950's and 1960's the MSU system tended to add new generating units in the southern part of the system to take advantage of cheap oil and gas reserves in Louisiana. *See* 26 FERC at 65,100; 30 FERC at 65,143. In the late 1960's, however, the system began a program of adding coal and nuclear generating capacity, 30 FERC at 65,144. that eventually resulted in the collapse of the investment equalization program.

AP&L was the first operating company to make such an investment in nuclear power. AP&L had historically been both a short company and one with insufficient capacity to meet the requirements of its customers. 30 FERC at 65,143. Moreover, AP&L had been losing its long-term gas contracts while Louisiana and Mississippi continued to have an adequate supply of gas and oil. 26 FERC at 65,101. In December 1974 AP&L brought on

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[11] *See also* 30 FERC at 65,143-44 (indicating that the units added in the 1960's and early 1970's were priced between $58 and $97 per kilowatt).

[12] ALJ Liebman also credited testimony indicating that two other factors promoted equalization of overall generation costs. First, responsibility for adding new capacity generally rotated among the operating companies, evening out investment costs over time. Second, the burden borne by companies adding relatively more expensive new capacity was often offset by the lower fuel costs associated with such units. *See* 26 FERC at 65,100.

line MSU's first nuclear plant, Arkansas Nuclear One (ANO) Unit 1.

Although ANO 1's capacity was substantially more expensive than that of non-nuclear generating units built at the time,[13] 26 FERC at 65,100-01, the lower fuel costs of a nuclear unit made the *total* generation costs of ANO 1 comparable to those of other plants brought on line in the 1970's.[14] Thus it is fair to say that the basic system of roughly equalizing the costs and benefits derived from the system's investment in new capacity remained intact.[15]

The picture changed radically with the development of two new nuclear units—the Waterford 3 unit (assigned to LP&L) and Grand Gulf 1 (initially assigned to MP&L). Grand Gulf was initially projected to cost $1.2 billion for two generating units.[16] Regulatory delays, additional construction requirements, and severe inflation ran up Grand Gulf costs to in excess of $3 billion for one unit.[17] Similar cost over-runs marred the construc-

[13] Capacity cost of ANO 1 was $276 per kilowatt, nearly double that of the oil-fired units introduced by MP&L and LP&L during the same period. 26 FERC at 65,101; 30 FERC at 65,144.

[14] 30 FERC at 65,144. The initial cost was about 3 cents per kilowatt hour. 26 FERC at 65,101.

[15] Nor did this basic pattern change substantially with the introduction of ANO 2 in 1980. Although ANO 2 had cost substantially more per kilowatt than did ANO 1, AP&L's *total* nuclear capacity is still quite reasonably priced at $500 per kilowatt or 3-4 cents per kilowatt hour. *See* 30 FERC at 65,145.

[16] Grand Gulf, for example, was originally projected to come on line at a cost of approximately $500 per kilowatt, a price comparable to that of the average price per kilowatt of the two ANO units. 26 FERC at 65,103.

[17] This figure was presented in the Commission's initial opinion. 31 FERC at 61,632. In determining the allocation

tion of Waterford 3. *See Middle South Energy, Inc. and Middle South Services, Inc.*, 31 FERC ¶ 61,305, 61,654 (1985). These units produce the most expensive energy on the MSU system. Measured in dollars per kilowatt of generating capacity, the new units were five times costlier than the ANO units installed by AP&L.[18] Most important, although these two plants have been estimated to represent over 70% of the production costs of the MSU system, they apparently will produce only 13% of the electricity used on the system. 30 FERC at 65,121.

Under these conditions, continued application of a capacity equalization scheme that only sought to equalize *kilowatts* could no longer come close to equalizing investment *dollars*. Any operating company saddled with re-

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of Grand Gulf capacity the Commission adopted the figures used by ALJ Liebman in his initial decision. *Id.* at 61,657. ALJ Liebman relied on the following cost estimates: $2.5 billion for Grand Gulf 1 and $2.4 billion for Waterford 3. *See* 26 FERC at 65,107. These figures represent the cost of these units as of December 31, 1981, rather than on the date of commercial operation (which was several years later). Thus ALJ Liebman conceded that the projected cost of Grand Gulf 1, as of 1984, was $2.8 billion. *See id.*

ALJ Head relied on a different, higher, and presumably more recent, set of figures. His conclusion that the new nuclear units would cost approximately $2,500 per kilowatt, 30 FERC at 65,121, was based on the testimony offered by Mr. Louiselle, a witness for LPSC, who, in the portion of the transcript cited by the ALJ, assumed that MSE's 90% share of Grand Gulf 1 would cost $2.92 billion and Waterford 3 would cost about $2.76 billion. *See* 483-R. 4124-26, VI JA 1452.

[18] ALJ Head estimated that Grand Gulf 1 and Waterford 3 would come on line at a cost of $2,500 per kilowatt. By contrast, he found that the two ANO units came on line at a cost of about $500 per kilowatt. 30 FERC at 65,121. ALJ Liebman estimated that Grand Gulf 1 would come on line at a cost three to four times greater than that of any unit already on the MSU system. *Id.* at 65,103.

sponsibility for Waterford 3 and/or Grand Gulf would likely find itself paying far more per kilowatt of capacity than would an operating company that was free of such a burden. 26 FERC at 65,100.

It is true that MSU filed a new System Agreement in 1982 altering its previous equalization scheme. Unlike the 1973 Agreement, which had pegged equalization payments to the cost of the long company's most recent generating addition, the 1982 Agreement provided for equalization payments based on the long company's "intermediate" (*i.e.*, oil and gas) units. 483-R. 7137-50, VII JA 1589-96. This change reduced the burden on any company that might be *both* short and have substantial responsibility for the new nuclear plants.[19] But, as discussed below, this change did not eliminate the major inequities that nuclear power introduced to the MSU system.[20]

4. *The Grand Gulf plant.* The Grand Gulf project was initiated by MSU to meet the then projected demand for electricity by the *system as a whole.* 26 FERC at 65,101-02. By the late 1970's, however, it became clear that projected demand would fall well short of previous expectations.[21] Nonetheless, MSU continued to build Grand Gulf 1[22] on the assumption that the overall cost per

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[19] On the other hand, the new agreement did not provide for an entitlement to the "intermediate" kilowatts of energy produced by the long company. Thus the short company might still have to purchase expensive nuclear energy whenever it lacked the capacity to meet its native load. 30 FERC at 65,140.

[20] Moreover, the new equalization scheme actually made matters worse for any company that was both *long* and retained substantial responsibility for one of the new plants.

[21] Indeed, as ALJ Head observed, the entire MSU system now has much more capacity than it needs. 30 FERC at 65,169.

[22] MSU, however, did halt construction of the second unit in the project, Grand Gulf 2. 31 FERC at 61,668 n.2. The Commission therefore did not decide on the allocation of

kilowatt hour would be less than that of alternative energy sources. 26 FERC at 65,102.[23]

Initially the plant had been assigned to MP&L.[24] It soon became apparent, however, that MP&L did not have the resources to finance the construction of the plant. As a consequence, MSU made a system decision to form Middle South Energy (MSE) in 1974 as a vehicle for financing Grand Gulf. MSE acquired full title to Grand Gulf. In June of 1974 all four Middle South operating companies entered into an "Availability Agreement" under which each operating company put its credit behind Grand Gulf.

Notwithstanding this initial agreement, at the time MSE was first formed no clear plan existed to allocate responsibility for Grand Gulf's capacity to each of the companies. Over the years various allocation plans were put forward, ultimately resulting in the Unit Power Sales Agreement (UPSA) at issue in this case.

Grand Gulf 2 costs, finding that issue to be purely speculative at this time. *Id.* at 61,669 n.20.

[23] This assumption is now questionable. Through the 1990's Grand Gulf will *not* produce energy that is cheaper than energy produced from alternative sources. Indeed, ALJ Liebman estimated that by 1993 ratepayers will pay $3 billion more for Grand Gulf energy than they would for energy from comparable sources. As of 1984 MSU was still predicting that Grand Gulf power would become economical at some future date and that at some (even later) point the project will represent a net benefit to consumers. 26 FERC at 65,103. As ALJ Liebman noted, however, the decline in the price of oil makes these projections appear rather dubious. *Id.*

[24] Grand Gulf is located in Port Gibson, Mississippi. Under the original plan each operating company in the system would be responsible for the financing and construction of a major nuclear facility. It was soon determined, however, that the site for the NOPSI plant near New Orleans was unsuitable; that unit was transferred to Mississippi. Responsibility for construction of both units shifted to MP&L. 26 FERC at 65,102.

At first it was contemplated that MSE would become a party to the System Agreement. Under this plan all of Grand Gulf would be a "participation unit" and responsibility for the plant's capacity would shift among the operating companies to the degree they were short. 616-R. 4122-23, II JA 505.

In 1979 MSU officials, having come to the conclusion that a fixed allocation of capacity was preferable to a scheme of shifting responsibilities, recommended a plan that would have allocated a share of Grand Gulf capacity to all of the operating companies.[25] But by early 1980 the MSU officers were moving toward a scheme absolving AP&L of all responsibility for Grand Gulf. In July of 1980 the CEOs of the MSU operating companies signed a Memorandum of Understanding, freeing AP&L of all responsibility for Grand Gulf. Although this Memorandum was never submitted to the Coordinating Committee, and therefore never became final, its basic terms were set forth in a "Reallocation Agreement" executed in July 1981. 616-R. 3275, I JA 268. Under the Reallocation Agreement AP&L assigned its entitlement to purchase Grand Gulf power to the other companies.[26] In addition,

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[25] In 1979 the Operating Committee of the MSU system recommended "Plan 4A" under which the operating companies would have the following responsibilities:

Company	Percentage
AP&L	11.11
LP&L	13.51
MP&L	49.60
NOPSI	25.78

26 FERC at 65,102. Although "Plan 4A" was tentatively approved by the MSU Board of Directors in November of 1979, the Board soon retreated from this position and, in January of 1980, approved an allocation plan quite similar to the UPSA. *Id.* at 65,103.

[26] In 1981 AP&L's share of Grand Gulf power under the Availability Agreement was calculated to be 17.1%, with

NOPSI, LP&L, and MP&L agreed to indemnify AP&L for any obligation it might incur to MSE's creditors. The Reallocation Agreement thus relieved AP&L of any responsibility for Grand Gulf capacity costs and provided the basis for the Unit Power Sales Agreement. 26 FERC at 65,103.

The Unit Power Sales Agreement was executed on June 10, 1982. Although all of the operating companies are signatories to the UPSA, it only provides for sale of Grand Gulf capacity and energy by MSE to three of the operating companies: LP&L, MP&L, and NOPSI, but *not* to AP&L. 26 FERC at 65,095.[27]

B. *The Proceedings Below*

In April 1982 MSU filed with the Commission the 1982 System Agreement, which set the general rules governing transactions between the operating companies, including capacity equalization payments and the rates governing the exchange of energy between the operating companies. FERC set the proceeding for hearing before ALJ Head. In June 1982 MSU filed the Unit Power Sales Agreement with the Commission, governing the sales of Grand Gulf capacity and energy by MSE to the four operating companies. This proceeding was set for hearing before ALJ Liebman.[28] ALJ Liebman issued his opinion

LP&L responsible for 26.9%, MP&L responsible for 31.3%, and NOPSI responsible for 24.7%. 26 FERC at 65,102.

[27] UPSA assigns LP&L the entitlement to purchase 38.57% of the power available to MSE from Grand Gulf, MP&L 31.63%, and NOPSI 29.80%. 26 FERC at 65,097 (excluding Unit 2 percentages). MSE only owns 90% of Grand Gulf; 10% has been sold to South Mississippi Electric Power Association. *Id.* These figures therefore only refer to percentages of MSE's share of the Grand Gulf facility.

[28] By order issued August 25, 1982 the Commission accepted the UPSA for filing but found that it constituted a rate change rather than an initial rate filing; FERC therefore

on February 3, 1984, *Middle South Energy, Inc.*, 26 FERC ¶ 63,044 (1984), and ALJ Head issued his opinion a year later, on February 4, 1985. *Middle South Services, Inc.*, 30 FERC ¶ 63,030 (1985). Both decisions touched on the allocation of Grand Gulf power, and FERC reviewed both decisions in an opinion issued June 13, 1985. *Middle South Energy, Inc. and Middle South Services, Inc.*, 31 FERC ¶ 61,305 (1985). It revisited the issue following petitions for rehearing in an opinion issued September 28, 1985. *Middle South Energy, Inc. and Middle South Services, Inc.*, 32 FERC ¶ 61,425 (1985).

1. *ALJ Liebman's decision in the UPSA case (ER82-616).* The principal issue[29] in ER82-616 was whether the UPSA's proposed allocation of Grand Gulf invest-

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suspended the rates which were to become effective under the UPSA, subject to refund. *See Middle South Energy, Inc.*, 20 FERC ¶ 61,206 (1982). On May 24, 1983 the Commission recharacterized the UPSA as an initial rate, but held that it had the authority to suspend initial rates. *Middle South Energy, Inc.*, 23 FERC ¶ 61,277 (1983). In *Middle South Energy, Inc. v. FERC*, 747 F.2d 763, 772 (D.C. Cir. 1984), this court reversed the Commission, holding that the Federal Power Act only permits suspension of changed rates.

On remand FERC determined that the Sales Agreement rates were changed rates after all, giving it authority to suspend them subject to refund. That decision was appealed to this court, but the appeal has been held in abeyance pending the outcome of this case. *See Arkansas Power & Light Co. v. FERC*, No. 85-1504 (D.C. Cir., filed Aug. 14, 1985). As matters stand, the rates filed in the UPSA were never suspended because FERC issued its final decision in Order No. 234, amending the UPSA, before service from Grand Gulf commenced. As we uphold FERC's decision here, the question whether the rates filed in the UPSA are subject to the suspension power of the Commission is now moot.

[29] ALJ Liebman, ALJ Head, and the Commission all addressed myriad issues that are not presented in the petitions before this court. These issues are not discussed in this opinion.

ment costs was reasonable and, if not, how such costs should be allocated. As a threshold matter, however, ALJ Liebman rejected a series of arguments suggesting that FERC did not have jurisdiction or statutory authority to amend this aspect of the UPSA.[30]

Having found jurisdiction, ALJ Liebman found that the UPSA was "unduly discriminatory" under Section 206(a) of the Federal Power Act, 16 U.S.C. § 824e(a) (1982),[31] because it failed to allocate any portion of Grand Gulf's capacity costs to AP&L. He based this decision on his view of the MSU system as a highly integrated operation that made critical decisions—such as the decision to move into nuclear power—as a unit. Under that view ALJ Liebman thought it only fair that AP&L pay its share of the company's decision to build nuclear capacity. Having rejected the UPSA's allocation of Grand Gulf costs, ALJ Liebman was faced with three alternatives:

> (1) Making Grand Gulf a participation unit, with floating responsibility among the short(er) companies.[32]
>
> (2) Allocating responsibility for Grand Gulf capacity proportionate to each operating company's relative share of system demand, as fixed in 1982.[33]

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[30] He rejected, *inter alia*, the following arguments: (1) the reallocation of Grand Gulf costs violated the *Mobile-Sierra* doctrine, 26 FERC at 65,113-16; (2) the reallocation constituted a forced purchase of power barred by the Act, *id.* at 65,115-17; and (3) the PUHCA gives the Securities and Exchange Commission primary authority over the allocation of Grand Gulf costs, *id.* at 65,117.

[31] Section 205(b), 16 U.S.C. § 824d(b) (1982), similarly bars any "undue preference" in wholesale rates.

[32] This proposal was put forth by the Mississippi Public Service Commission.

[33] This proposal was put forward by the City of New Orleans. On appeal CNO has abandoned this view and adopted

(3) Allocating responsibility for Grand Gulf such that each operating company bore a share of the cost of *all* the nuclear units on the MSU system proportionate to that company's relative share of system demand, as fixed in 1982.[34]

26 FERC at 65,109.

ALJ Liebman chose the last proposal. As the Commission noted, this approach did not merely allocate the cost of Grand Gulf. By including the total system investment in nuclear power in his formula, ALJ Liebman effectively reallocated the costs of all nuclear capacity on the MSU system. 31 FERC at 61,633.

ALJ Liebman justified his exclusive focus on nuclear capacity costs—rather than on equalizing the costs of all

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that of ALJ Head, *i.e.*, the allocation of Grand Gulf capacity alone—and not that of all nuclear plants—but calculating that allocation on the basis of each company's relative demand for system load in any particular year. *See* Brief of Petitioner City of New Orleans, Louisiana at 48.

[34] This proposal was originally put forward by the Louisiana Public Service Commission and Occidental Chemical Corporation. As the Commission suggested, this alternative can be broken down into the following three-step process:

(1) *Calculating each company's nuclear responsibility ratio.* This ratio consists of each operating company's 1982 share of the system's total demand over the entire system's demand.

(2) *Calculating each company's share of total system nuclear investment.* This figure is derived from multiplying the total system investment in nuclear power by a company's nuclear responsibility ratio.

(3) *Calculating each company's share of Grand Gulf costs.* This amount equals the shortfall between the operating company's proportionate share of nuclear costs (estimated in step 2 and that company's own nuclear investment.

Each company would then receive an entitlement to Grand Gulf power corresponding to its relative contribution to Grand Gulf investment costs. 30 FERC at 61,655.

capacity investment or, even more sweeping, equalizing all generating costs—by claiming that the differences among non-nuclear base load [35] generation costs were minor compared to the cost differences among the nuclear generating facilities. 26 FERC at 65,110. He suggested that even under his proposal AP&L would still have the lowest total generation costs on the system. *Id.* at 65,119. He justified his decision to reallocate costs of Grand Gulf primarily by reference to the fact that the UPSA perpetuated discrimination caused by the timing of nuclear units by forcing the Louisiana and Mississippi ratepayers to pay about four times more for nuclear capacity than the Arkansas ratepayers would pay for their nuclear kilowatts. *Id.* at 65,107.

2. *ALJ Head's decision in the System Agreement case (ER82-483).* The principal issue in the System Agreement proceeding was whether FERC should approve that Agreement as filed or whether it should equalize [36] all or part of the production costs on the system. 30 FERC at 65,120. ALJ Head also considered a series of arguments militating against FERC jurisdiction over the reallocation of Grand Gulf costs and rejected them.[37]

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[35] "Base load" units are those units that are in continuous operation. By contrast, reserve units (oil and gas units) can be fired up quickly to meet special surges in demand. 483-R. 7112, VII JA 1564.

[36] In this context "equalization" does not mean that each operating company would pay the same absolute number of dollars. Rather, it means that each operating company would have to pay a share proportionate to its share of system demand.

[37] He rejected the following contentions: (1) that a reallocation of Grand Gulf costs violates the *Mobile-Sierra* doctrine, 30 FERC at 65,146-47; (2) that such a reallocation violates the ban on federal regulation of "generating" facilities contained in § 201(b) of the FPA, 16 U.S.C. § 824(b) (1982), 30 FERC at 65,148-50; (3) that such a reallocation constitutes a "forced sale" of power, barred by § 202(b) of the FPA,

Having found that FERC had the authority to reallocate production costs, ALJ Head faced the following alternatives:

(1) *Adoption of the System Agreement as filed.* This would entail allocating none of the Grand Gulf costs to AP&L and only equalizing the costs of capacity between "long" and "short" companies, with equalization payments pegged to the cost of the long companies' oil and gas investment costs.[38]

(2) *Equalization of production costs.* The basic concept,[39] presented by the Louisiana Public Service

16 U.S.C. § 824a(b) (1982), 30 FERC at 65,154; (4) that such a reallocation expands federal regulation of a utility's rate base in a manner that improperly limits the power of the states over retail rates, 30 FERC at 65,149-51; (5) that the Public Utility Holding Company Act, 15 U.S.C. § 79 *et seq.* (1982), bars FERC jurisdiction in this matter, 30 FERC at 65,152-54; and (6) that the reallocation of Grand Gulf costs by FERC would present an obstacle to state certification of new generating plants. 30 FERC at 65,154.

[38] 30 FERC at 65,139. This proposal was supported by AP&L and various Arkansas interests in the proceedings before ALJ Head. The Arkansas parties continue to press this position on appeal.

[39] There were two variations on this theme:

(a) *Base load equalization.* This proposal would have required each operating company to bear a share of the system's "base load" (coal and nuclear) capacity proportionate to its share of system load. 30 FERC at 65,140. This proposal was supported by the Commission staff in the proceedings before ALJ Head and was before the Commission. 31 FERC at 61,635 & n.5. No party, however, has pressed this position on appeal.

(b) *Base load equalization combined with rough equalization of intermediate capacity.* This proposal would require base load capacity to be allocated in proportion to relative system demand while all other capacity would be equalized under the terms of the 1982 System Agreement, *i.e.*, short companies would compensate long com-

Commission, was to allocate responsibility for a share of *all* production costs on the MSU system proportionate to each company's share of the system's total load.[40]

(3) *Making Grand Gulf a participation unit.* This proposal would allocate responsibility for Grand Gulf capacity to each operating company to the degree that the company in question was "short." Under this scheme responsibility for Grand Gulf capacity would shift over time.[41]

ALJ Head rejected all of these proposals. He rejected the concept of making Grand Gulf 1 a participation unit primarily because it would allow long companies (*e.g.*, MP&L) to avoid completely the high front-end costs associated with that plant. 30 FERC at 65,166-67. He rejected the equalization proposals on the ground that overall cost equalization would be inconsistent with the general "pattern of autonomy * * * particularly as to * * * specific plant site locations, fuel and financing" that he found characterized the operating companies in the MSU system. *Id.* at 65,168.

ALJ Head found support for his finding of a "pattern of autonomy" in two circumstances. First, he stressed that the historic practice in the MSU system was to equalize only *excess* capacity. *Id.* at 65,167. Second, he

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panies, with equalization payments pegged to the cost of the long companies' intermediate (oil and gas) units 30 FERC at 65,141. This proposal was put forward by the City of New Orleans before ALJ Head and the Commission. 31 FERC at 61,635 & n.6. It is not pressed on appeal.

[40] 30 FERC at 65,141. This proposal was put forward by the Louisiana Public Service Commission. It continues to press this position on appeal.

[41] 30 FERC at 65,141. This proposal was put forward by the Mississippi Public Service Commission. MPSC continues to press this position on appeal.

insisted that "generation additions in almost every instance (except for Grand Gulf) were made primarily to satisfy individual company needs." *Id.* at 65,168.[42]

ALJ Head, however, found that Grand Gulf constituted an "anomaly" in the MSU system:

> Grand Gulf from its inception was planned, presented to the licensing authorities and constructed as a system plant not only to serve the needs of MP&L but to serve the needs of all the operating companies on the system.

30 FERC at 65,170.[43]

He therefore deemed it appropriate to reject the System Agreement as filed and to allocate the costs of the Grand Gulf investment among all of the operating companies. Unlike ALJ Liebman, however, he held that this allocation should fluctuate from year to year to track each company's relative demand for the system's energy. 30 FERC at 65,172.

3. *FERC's initial decision.*[44] In Order No. 234 the Commission summarily affirmed both ALJs on the thresh-

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[42] Even ALJ Head conceded, however, that all of the operating companies would benefit from the economies of scale realized when an individual company built a plant providing more capacity than that company could absorb at the time. Moreover, he found that MSU was a "highly integrated system" which sought to achieve such economies of scale through "common planning." 30 FERC at 65,168.

[43] Specifically, ALJ Head was impressed by the following facts: (1) the Grand Gulf project was an amalgam of the nuclear units assigned to MP&L and NOPSI; (2) the plant was planned on the basis of the combined load forecasts of all of the operating companies; (3) it was clear all along that the facility would produce much more energy than MP&L could ever use; and (4) the Atomic Energy Commission approved the Grand Gulf license because the entire system had placed its credit behind MSE. 30 FERC at 65,170-71.

[44] FERC reviewed both ALJs' decisions in issuing Order No. 234, even though it had previously declined to consolidate

old issue of its own jurisdiction to amend the Sales Agreement and the System Agreement. 31 FERC at 61,643-46.[45] On the merits, the Commission affirmed both ALJs' findings that MSU constituted an "integrated electric system." 31 FERC at 61,645. The Commission, however, specifically rejected ALJ Head's finding that the MSU system displayed a "pattern of autonomy" with regard to the planning and construction of generating units. *Id.*

The Commission conceded that MSU's system of overlapping officers and directors and the representation of the operating companies on the System Operating Committee gave the operating companies substantial influence in the development of the system's plans. *Id.* at 61,646. FERC further observed that the individual companies used their influence to seek the addition of generating units that met their particular needs, and that Section 4.01 of the System Agreement made each operating company responsible for financing the ownership or purchase of the generating capacity necessary to service its customers. *Id.* at 61,649. The Commission nonetheless concluded that "major critical decisions, including decisions to build new generating units, are made by the Operating Committee for the benefit of the system as a whole." *Id.* at 61,646. *See also id.* at 61,650.

The Commission buttressed its conclusion with the following evidentiary support: (1) Section 4.01 of the 1982 System Agreement provides that the Operating Committee shall "determine" the system generation addition plans;[46] (2) at least five witnesses testified that new

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the two cases. *See* 21 FERC ¶ 63,039 (1982), *aff'd,* 22 FERC ¶ 63,015 (1983).

[45] The Commission rejected the jurisdiction arguments ALJ Head had considered in the System Agreement case, *see* note 37 *supra,* with the exception of the state certification challenge.

[46] The 1973 System Agreement had stated that the Operating Committee "assigns" responsibility for new generating

units were added to address the needs of the system as a whole, *id.* at 61,646-48; and (3) the Operating Committee minutes over a twenty-year period revealed that the Committee had the responsibility and the authority to make the "critical decisions" concerning the addition of generating capacity. *Id.* at 61,648-49.

The Commission's review of the Operating Committee minutes revealed that the Operating Committee did not merely rubber-stamp the requests of the individual operating companies concerning the addition of generating capacity. *Id.* at 61,649. The Commission found that the Operating Committee consistently based its generation plans on the needs of the system as a whole. *Id.* at 61,649-50. It found that the Operating Committee had authority over the general timing, location, and size of plant additions, while the individual operating companies retained authority to fill in the details of such fundamental decisions. *Id.* Thus FERC stated that there was no evidence in the record that an operating company had ever built a new plant without a recommendation from the Operating Committee or that one had ever refused to carry out such a recommendation. *Id.* at 61,651.[47]

In light of this finding, FERC rejected ALJ Head's contention that Grand Gulf was an "anomaly." Instead it agreed with ALJ Liebman that Grand Gulf, like every other generating station, was built to serve the needs of

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units to particular operating companies; the 1982 System Agreement does not use the word "assigns." Notwithstanding this change, the Commission found the 1982 Agreement to vest the same authority in the Operating Committee over allocation of responsibility for generating units as had existed in previous System Agreements. 31 FERC at 61,646.

[47] The Commission also noted that changes in the 1982 Agreement had enhanced the power of the Operating Committee to override the wishes of an individual operating company by providing for majority rule rather than a two-thirds vote. This provision made it impossible for a single company to block a Committee decision. 31 FERC at 61,651.

the system as a whole and to attain the system-wide goal of diversifying MSU's fuel mix. *Id.* at 61,653. MSE was deemed a mere financing shell that the Commission hypothesized would have been made available to any other operating company that suffered the financial difficulties encountered by MP&L. *Id.* at 61,654.

The Commission viewed the decision to move into nuclear power as a system-wide decision calculated to meet system-wide needs. It found that MSU's nuclear project had run afoul of unforeseen economic difficulties that had disrupted the system's historic rough equalization of generation costs. FERC therefore adopted ALJ Liebman's scheme [48] of allocating Grand Gulf costs so that each operating company would contribute proportionately to the system's investment in nuclear capacity. *Id.* at 61,655.[49]

4. *FERC's opinion on rehearing.* In Opinion No. 234-A FERC clarified its position on the various jurisdictional arguments it had addressed in its initial decision. 32 FERC at 61,943-52. The Commission also addressed—and rejected—the argument raised by various Arkansas parties that FERC lacked jurisdiction as there was no interstate sale of power. The Commission suggested that, whatever the merits of such an argument where a "monolithic" system is concerned, there was no question but that the transfer of power among the MSU operating companies constitutes a "sale for resale." *Id.* at 61,957.

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[48] The Commission declined to update the cost estimates for the Grand Gulf and Waterford 3 units, stating that both the cost and pertinent demand projections were constantly changing. 30 FERC at 61,657.

[49] In its initial decision the Commission did not expressly discuss the rationality of the alternatives to ALJ Liebman's approach presented in the record of ER-483. It implicitly addressed these concerns by adopting the ALJ's analysis. 31 FERC at 61,655.

Indeed, a major portion of the Commission's opinion on rehearing was dedicated to clarifying the Commission's essential finding concerning the "integrated" character of the MSU system. The Commission rejected any attempt to mischaracterize its decision as based on a view that MSU is a "monolith." *Id.* at 61,952. FERC simply insisted that, whatever the powers of the individual operating companies, the MSU Operating Committee makes the "*major* critical decisions on the System, *primarily* for the System as a whole." *Id.* at 61,953 (emphasis in original).[50] The Commission emphasized that its opinion hinged on "a variety of factors including the manner in which decisions are made by the commonly owned affiliates, and for whose primary benefit those decisions are made." *Id.* at 61,956.

Turning to the merits, the Commission addressed three challenges to the rationality of its allocation of Grand Gulf costs. It disputed the contention of the Arkansas parties that the allocation violated the spirit and practice of the MSU system, the System Agreement, and the intent of the parties to that Agreement. FERC responded that the clear intent of the System Agreement was to correct major cost imbalances while moving toward a mixed fuel base including nuclear and coal-fired facilities. The Commission insisted that it need not measure the rationality of its allocation from the vantage point of the parties at the time the UPSA was first negotiated. *Id.* at 61,957-59.

The Commission also addressed the argument of MP&L that the Commission's order had only exacerbated the

[50] FERC also disputed AP&L's contention that at least on one occasion an operating company had refused to build a unit despite a "recommendation" by the Operating Committee that it do so. FERC noted that although it was true that LP&L had never built coal units in northern Louisiana in the early 1980's, there was no record evidence suggesting actual defiance of the Operating Committee. 32 FERC at 61,953-54.

discrimination it would have suffered under the original UPSA scheme. MP&L noted that under the UPSA it would have been responsible for 31.63% of Grand Gulf, but under the Commission's scheme it would be responsible for a full 33%. 31 FERC at 61,959. Under the new scheme Mississippi would receive only 9.5% of the system's nuclear capacity while paying for 15% of the system's nuclear investment. 32 FERC at 61,964 n.26.

The Commission responded by asserting that the mere fact that FERC's order increased MP&L's burden did not make it more discriminatory. It is completely rational, argued the Commission, that a smaller burden can be discriminatory and, with a change in the relative standing of the parties, a larger burden can be fair. The original allocation was discriminatory, in the Commission's view, because AP&L had failed to share the burden of Grand Gulf. Although the Commission's order would increase MP&L's allocation somewhat, it would spread the overall burden of Grand Gulf more equitably by making AP&L carry a portion of the burden.

The Commission suggested that its refusal to reallocate the capacity of all nuclear units (as well as their costs) was justified by the MSU system's historic aversion to equalizing all costs per kilowatt. *Id.* at 61,959. It stressed the same point in responding to the arguments of various Louisiana parties that it should have adopted full cost equalization. *Id.* at 61,961. Thus the Commission depicted its opinion as an attempt to balance

> the need to provide an equitable sharing of the investment costs of units that have (or could have) become unforeseeably high due to the unique problems associated with nuclear construction, and the need to recognize the efforts of individual companies on the System and allow them to retain the benefits of units they own to the fullest extent possible.

Id.

Dissatisfied with this rationale, petitioners sought review in this court.

II. JURISDICTION

The petitioners from Arkansas, Missouri and Mississippi raise certain threshold challenges to the Commission's decision. They contend that FERC lacks jurisdiction to modify the allocation of the capacity costs of Grand Gulf embodied in the Unit Power Sales Agreement ("UPSA"). We disagree, and hold that the Federal Power Act ("FPA" or "the Act")[51] provides FERC with authority to issue the orders in question. Initially, we will set forth the affirmative basis of FERC's jurisdiction; thereafter, we will address (and reject) each individual counterargument raised by petitioners.

A. *The Jurisdiction of the Commission*

Section 201 of the Act contains the Commission's basic jurisdictional grant.[52] It provides that "[t]he provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce" and that "[t]he Commission shall have jurisdiction over all facilities for such transmission or sale . . . ." This section also defines "public utility" as "any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter."[53] The facts here reveal that MSE sells Grand Gulf's energy to the affiliated operating companies of the MSU system at wholesale in interstate commerce. Thus, under section 201 of the Act, MSE is a "public utility" and FERC retains jurisdiction over its sales and facilities.

Sections 205 and 206 of the Act set forth the Commission's remedial authority. Section 205(a) establishes a

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[51] 16 U.S.C. §§ 824 *et seq.* (1982).

[52] *Id.* § 824. The states retain jurisdiction over retail rates.

[53] *Id.* § 824(e).

threshold requirement that all "rates and charges" made by a public utility, and "all rules and regulations affecting or pertaining to such rates and charges," must be "just and reasonable," or they will be deemed "unlawful."[64] Most significantly for our purposes, section 206 provides that when the Commission, after a hearing, determines that

> any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, *or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.*[65]

The combined force of these provisions leads inexorably to the conclusion that, under the circumstances presented in the instant case, FERC had jurisdiction to modify the Grand Gulf allocation set forth in the UPSA.

The distribution of Grand Gulf costs and capacity in the UPSA inevitably affects each operating company's generation costs and, by extension, their wholesale rates. When, as here, generation capacity has been built and planned on a profoundly integrated basis, the Commission properly may examine its allocation as a cost component affecting wholesale rates. For this purpose, the UPSA cannot be examined in isolation. As the Commission stated, the UPSA is "an agreement which 'supple-

[64] 16 U.S.C. § 824d(a) (1982). Section 205(b), 16 U.S.C. § 824d(b) (1982), further provides that no public utility shall, with respect to any jurisdictional sale, "maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, . . . between localities . . . ."

[65] *Id.* § 824e(a) (emphasis supplied).

ments or supersedes' the coordination arrangements among the MSU utilities, and . . . is a contract 'affecting' rates under the 1982 System Agreement." [56]

The UPSA serves to distribute the Grand Gulf capacity available to MSE—and its cost—among the MSU operating companies. When the Commission acted to modify the UPSA and reallocate the capacity of Grand Gulf, it altered the relative amount of system capacity ultimately paid for by each affiliate. Concurrently, the 1982 System Agreement (Service Schedule MSS-1) established the terms of reserve capacity cost-sharing among the same group. Any change in the allocation of the capacity costs of Grand Gulf in the UPSA will change the relative "longness" or "shortness" of each company under the System Agreement, thus altering the equalization payments made and received for capacity under Service Schedule MSS-1. In the instant case, the cost burden of system generating capacity has been shifted among the affiliates, by virtue of Commission action and system agreement, in order to insure an equitable distribution.[57]

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[56] 32 FERC ¶ 61,425, at 61,949-50 (quoting 31 FERC ¶ 61,304, at 61,627 (1985) (Order on remand)).

[57] The Commission explained the effect of the intersection of the UPSA and the 1982 System Agreement as follows:

> The impact of these Grand Gulf allotments (or any other Grand Gulf allotments) on reserve equalization under Service Schedule MSS-1 of the 1982 System Agreement will likely be a change in the shortness or longness of each member. For example, when Grand Gulf 1 becomes commercially operable, to the extent that the fixed Grand Gulf allotment ratio exceeds (or is exceeded by) the monthly 1982 System Agreement responsibility ratio for a given pool member, that member will become either more long (or short) or less long (or short) for pool reserve equalization purposes. The excess capacity of the long members will be equalized in accordance with the 1982 Agreement, i.e., to the extent a member having excess capacity cannot reach voluntary agreements to sell its excess capacity and energy under Service Schedule

This equitable distribution is mandated by the FPA because of the historical integration of the MSU system.

Capacity costs are a large component of wholesale rates. Thus, the capacity costs of the system carried by each affiliate will significantly affect the wholesale price it pays for energy on the MSU system. In the Commission's view, the UPSA's allocation of Grand Gulf, combined with the provisions of the 1982 System Agreement, created serious inequities in the division of costs of power resources among the operating companies *in light of the integrated planning for generating capability on a system basis.* Unreasonable disparities in the shares borne by affiliates of the total costs of the system's generating capacity plainly "affect" the wholesale rates at which the operating companies exchange energy, and therefore require remedial action by the Commission pursuant to section 206.

A case involving the Northern States Power ("NSP") Companies, *State of Minnesota v. FERC,*[58] provides a helpful illustration of how agreements among affiliates can "affect" rates. The NSP Companies develop and operate both generation and transmission facilities on an integrated basis through participation in a Coordinating Agreement which, *inter alia,* establishes procedures for sharing costs on the system. In 1982, the Companies filed an amendment to that Agreement with FERC proposing a methodology for determining the rate of return on investment as a component of the fixed costs shared

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MSS-4 (Unit Power Purchase), its excess capacity will be equalized among the short members based on the costs of the long member's intermediate generating units under Service Schedule MSS-1 (Reserve Equalization). Any excess energy will be shared with the pool under Service Schedule MSS-3 (Exchange of Electric Energy Among the Companies).

31 FERC ¶ 61,305, at 61,656.

[58] 734 F.2d 1286 (8th Cir. 1984).

under that Agreement. The Minnesota Public Utilities Commission ("MPUC") intervened and contended that FERC lacked jurisdiction to review the amendment because the Coordinating Agreement does not establish a wholesale rate. Specifically, MPUC argued that FERC "exceeded its authority under the Federal Power Act and intruded upon retail ratemaking functions by accepting a filing that sets a rate of return on capital as part of a cost allocation agreement between affiliated power companies." [59]

The Eighth Circuit observed that "MPUC's challenge to the Commission's jurisdiction rests on its contention that the Coordinating Agreement serves simply as a mechanism for allocating costs among the NSP Companies and does not establish a wholesale rate for the resale of electricity." [60] However, the court agreed with the Commission that the Coordinating Agreement "contain[ed] numerous provisions authorizing the NSP Companies to exchange electric power among themselves in return for payment," *i.e.*, interstate wholesale transactions. Thus, the Eighth Circuit held that the Coordinating Agreement established a wholesale rate and that, "[b]ecause a change in the rate of return on investment affects the wholesale rate under the Coordinating Agreement, the Commission possessed jurisdiction to review and approve the proposed amendment." [61]

We are in total accord with the Eighth Circuit's view of FERC's jurisdiction as enunciated in *State of Minnesota*. In the instant case, the petitioners concede that wholesale rates are established in the disputed contracts governing the MSU system; but petitioners nonetheless contend that the Commission does not have jurisdiction here because other portions of these same agreements

[59] *Id.* at 1287.

[60] *Id.* at 1288.

[61] *Id.* at 1289.

allocate generation costs among the MSU companies and these *particular* provisions do not themselves establish a wholesale rate. However, the petitioners ignore the critical point here that, while these provisions do not fix wholesale rates, their terms do directly and significantly *affect* the wholesale rates at which the operating companies exchange energy, due to the highly integrated nature of the MSU system. We conclude that, because the allocation of Grand Gulf capacity and costs, like the rate of return on capital in *State of Minnesota*, significantly *affects* the wholesale rates at which the operating companies exchange energy due to the combined effect of the UPSA and the 1982 System Agreement, that allocation is plainly within Commission jurisdiction.[62]

The Supreme Court quite recently confirmed the propriety of this analysis in *Nantahala Power & Light Co. v. Thornburg*.[63] In that case, FERC examined an agreement between two affiliated power companies, which allocated certain low-cost entitlement power between them.

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[62] In *South Dakota Public Utilities Comm'n v. FERC*, 690 F.2d 674 (8th Cir. 1982), a case also involving the NSP Companies, an amendment to the Coordinating Agreement allocated costs arising from the cancellation of a system nuclear plant project in Wisconsin. The court upheld FERC's decision that the NSP Companies would share the cancellation costs on the basis of a pre-existing arrangement equalizing generating costs in the Coordinating Agreement and quoted with approval the following language from the FERC order:

> The Amendment to the Coordinating Agreement of Northern States Power Company (Minnesota) and Northern Power Company (Wisconsin) filed with the Commission . . . is just and reasonable. It is approved as a rate schedule change pursuant to § 205 of the Federal Power Act subject to the modification ordered in Paragraph (B) below.

Id. at 677. It is noteworthy that no question was raised as to the Commission's jurisdiction to review this amendment to the Coordinating Agreement.

[63] 54 U.S.L.W. 4676 (U.S. June 17, 1986).

FERC found that the agreement was unfair to one of the companies, Nantahala, and increased the percentage of low-cost entitlement power that it should receive. Although FERC did not specifically "reform" the agreement, Nantahala was required to file revised rates, reflecting its increased entitlement to low-cost power. The North Carolina Utilities Commission ("NCUC") not only rejected the actual apportionment agreed to by the companies, but also "employed an allocation of entitlement power that nowhere [took] into account FERC's allocation of that same power." [64]

The Supreme Court held that the NCUC orders were inconsistent with preemptive federal law. The Court observed that

> [a]lthough the [companies' agreements] do not purport explicitly to set a sales price for power, FERC's decision on how Nantahala may treat these agreements in determining its wholesale rates obviously does affect Nantahala's costs directly, and thus Nantahala's wholesale rates.[65]

FERC's allocation of Grand Gulf's costs and capacity, like the setting of entitlement percentages in *Nantahala Power & Light*, does not set a sales price, but does directly affect costs and, consequently, wholesale rates. We cannot disregard the Supreme Court's clear and timely message that FERC's jurisdiction under such circumstances is unquestionable.

Having determined that all MSU generating capacity, including Grand Gulf, had been built and planned on an integrated basis by the MSU system to meet its collective needs and that the allocation of Grand Gulf would affect wholesale rates within the system, the Commission decided that the affiliated operating companies' arrange-

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[64] *Id.* at 4678.

[65] *Id.* at 4681.

ment for sharing of capacity costs—as set forth in the UPSA and the 1982 System Agreement—was unjust, unreasonable and unduly discriminatory. Under these circumstances, sections 205 and 206 of the FPA plainly provide FERC with authority to modify the Grand Gulf allocation agreed to by the operating companies.

B. *Arguments Opposing Jurisdiction*

The petitioners advance various theories to support their contention that FERC lacks jurisdiction to impose the remedy selected in this case. They maintain that: (1) FERC has unlawfully exercised jurisdiction over a generating facility; (2) FERC has unlawfully compelled a purchase of power and generating capacity; (3) FERC has impermissibly intruded on areas subject to state jurisdiction; (4) FERC has contravened the purposes of the Public Utility Holding Company Act ("PUHCA") and infringed upon the authority of the Securities and Exchange Commission ("SEC"); and (5) FERC has violated the *Mobile-Sierra* doctrine. As set forth below, none of these attempts to displace FERC's jurisdiction succeed.

1. *Jurisdiction Over Generating Facilities*

The Arkansas-Missouri petitioners contend that, in allocating the cost and capacity of Grand Gulf, the Commission has asserted jurisdiction over a generating facility in contravention of section 201(b) of the FPA. They maintain that the equalization of nuclear investment by reallocating generation costs falls outside of FERC's rate making jurisdiction and instead falls solely within state authority over generation.

In pertinent part, the statute states:

> The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, *except as spe-*

> *cifically provided in this subchapter and subchapter III of this chapter*, over facilities used for the generation of electric energy. . . .[66]

In the same section, the statute provides for

> *Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III* . . . .[67]

The Conference Report on the FPA instructs that the italicized phrases were "added to remove any doubt as to the Commission's jurisdiction over facilities used for the generation . . . of electric energy to the extent provided in other sections . . ."[68] The Commission concluded that, in the course of exercising its undisputed jurisdiction over interstate sales of electric energy at wholesale, it lawfully could reallocate the costs of Grand Gulf across the integrated system. Hence, the Commission reasoned that although allocating cost does, to some extent, result in the "regulation of matters relating to generation," such regulation is valid under the FPA when it is the byproduct of a legitimate exercise of FERC's power to regulate wholesale rates.

We agree that FERC has not exercised jurisdiction over generating facilities in any way that violates the FPA. Instead, the Commission is acting pursuant to its exclusive rate authority over wholesale transactions and its remedial authority as set forth in sections 205 and 206.

The Arkansas-Missouri petitioners concede that FERC has jurisdiction to modify the rates and rate-related terms of the UPSA, but deny that this authority encompasses the reallocation of generating capacity. Citing the congressional concern that states maintain control of gen-

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[66] 16 U.S.C. § 824(b) (1982) (emphasis supplied).

[67] *Id.* (emphasis supplied).

[68] H.R. REP. No. 1903, 74th Cong., 1st Sess. 74 (1935).

erating facilities,[69] they assert that the statutory prohibition of federal regulation of such facilities in section 201 (b) becomes meaningless if FERC is permitted to allocate the costs of a plant.

This analysis is flawed. As FERC correctly reasoned:

> We cannot interpret the "but" clause of Section 201 (b) (1) as nullifying the authority granted to us in the first sentence of Section 201 (b) (1), in situations where generation facilities are used for interstate wholesale sales. To interpret the statute otherwise would be inconsistent with the declaration in Section 201 (a) that Federal regulation of the sale of energy at wholesale in interstate commerce is necessary in the public interest.[70]

Nor could such an interpretation be reconciled with the Commission's statutory authority to revise contracts affecting rates which are unjust, unreasonable or unduly discriminatory.[71]

The petitioners' general assertion that FERC has improperly infringed upon a state realm by reallocating the costs of Grand Gulf will be dealt with separately *infra*; for the present purpose, it suffices to note that FERC has not regulated a facility, but rather the wholesale rates of interstate sales within the MSU system. It is well-accepted that FERC must allow the recovery of the cost of generating facilities in setting wholesale rates. Here, FERC has simply exercised its undisputed authority over the wholesale rates of electric generating facilities in interstate commerce, which includes, under the facts presented, the authority to reallocate the costs of Grand Gulf across the system. As the statute quite plainly states, FERC's control here is exclusive. The jurisdictional line

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[69] *See* § 201 (b) (1) of the FPA, 16 U.S.C. § 284 (1982).

[70] 32 FERC ¶ 61,425, at 61,947.

[71] *See* 26 FERC ¶ 63,044, at 65,113-14.

drawn by Congress is bright, and FERC stands on the correct side of that line.

The cases cited by the Arkansas-Missouri petitioners are inapposite. In *Connecticut Light & Power Co. v. FPC*,[72] the Supreme Court construed the "local distribution" exception to the Commission's jurisdiction, rather than the "generating facilities" exception, in the context of determining whether to permit regulation of an electric utility located and serving customers exclusively in the state of Connecticut. In its decision, the Court cited the language of section 201(a) of the FPA, "but shall not have jurisdiction . . . over facilities used in local distribution." The lower court had decided that this exemption did not preclude Commission regulation if the Act otherwise provided for the facilities' regulation, *i.e.*, if they carried energy in interstate commerce. The Supreme Court rejected this interpretation of the "but" clause and held that, in order to be subject to FERC jurisdiction, a company must own facilities used in the transmission of interstate power *and not be* a local distribution facility. From this, the petitioners reason that Grand Gulf must be used for interstate wholesale sales *and not be* a generating facility to be subject to FERC jurisdiction.

This interpretation must fail. Initially, we note that the distribution facility at issue in *Connecticut Light & Power* sold energy exclusively within Connecticut; MSE's sales are, without exception, at wholesale and in interstate commerce. Second, the holding in *Connecticut Light & Power* addresses only the "local distribution" exception to the FPA, not the "generating facilities" exception at issue here. Furthermore, the Court's limited discussion of the "generating facilities" exception refutes petitioners' contention. In this discussion, the Court accepts the proposition that FERC may lawfully assert jurisdiction over matters pertaining to generation where it is found that generation facilities are used as facilities for

[72] 324 U.S. 515 (1945).

interstate wholesale sales.[73] In the instant case, the MSE generating facilities are utilized solely for interstate wholesale sales, thus satisfying the Court's test.[74]

2. *Compelled Purchases of Power and Capacity*

The Arkansas-Missouri petitioners also argue that FERC has exceeded its jurisdiction by forcing independent companies—AP&L, for example—to purchase power from Grand Gulf in quantities beyond that agreed to in the UPSA. The Commission found that, as a factual matter, there would be no "forced purchase" due to the integrated nature of the Grand Gulf project and the MSU system and AP&L's individual longstanding, in-depth commitment to Grand Gulf. We agree with the Commission that "the issue here is not whether a company should be forced to purchase or sell power, but rather is the

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[73] 324 U.S. at 528 n.6. (The Court rejected the holding of a previous circuit decision in *Hartford Electric Co. v. FPC*, 131 F.2d 953 (2d Cir. 1942), *cert. denied*, 319 U.S. 741 (1943), but cited with approval the alternative rationale for that decision.)

[74] The Arkansas-Missouri petitioners also cite cases prohibiting FERC from ordering the wheeling of power, *Florida Power & Light Co. v. FERC*, 660 F.2d 668 (5th Cir. 1981), *cert. denied*, 459 U.S. 1156 (1983); *New York State Electric & Gas Corp. v. FERC*, 638 F.2d 388 (2d Cir. 1980), *cert. denied*, 454 U.S. 821 (1981); *Richmond Power & Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), or the modification of retail rates, *FPC v. Conway Corp.*, 426 U.S. 271, 276-77 (1976). They maintain that these cases demonstrate that even where the FPA grants power—such as the power over interstate wholesale sales of electric energy—"that grant must be reconciled with [the Act's] limitations on power, such as . . . the lack of jurisdiction over generating facilities." Arkansas Public Service Commission ("APSC") Brief at 28. These cases are inapposite here because, under the clear terms of the statute, the Commission has been awarded jurisdiction over generating facilities "to the extent provided in other sections," including jurisdiction necessary to effectuate regulation of interstate wholesale rates.

appropriate allocation of costs among integrated companies owned by the same parent." [75] The Commission has made detailed findings on the highly integrated nature of the MSU system and on the coordinated planning of the Grand Gulf project. The depth of the operating companies' historical involvement in both the system and the project allows the Commission to step in and reallocate costs under section 206(a) of the FPA so that each of the operating companies is treated fairly.

A consistent line of judicial precedent supports FERC's authority to approve and/or modify the terms of the pooling and coordination agreements of closely integrated power systems when it deems those arrangements unlawful as filed. Over thirty years ago, in *Pennsylvania Water & Power Co. v. FPC*,[76] the Supreme Court considered the Commission's authority to order continued integrated operations by two utilities. For more than 20 years, the companies had been interconnected and had bought and sold power in a coordinated fashion. The FPC ordered a significant reduction in the rates charged by one utility to the other, and the selling utility refused to comply. As a result, the Commission itself prescribed rate schedules to comply with its rate order, requiring the utility to "continue to *buy*, sell, and transmit power in the same coordinated manner" as in the past, though at the decreased rates. The utility objected, but the Supreme Court sustained the order, observing that the integration of utilities is a "practice" within the meaning of section 206 and that the Commission could order its

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[75] 31 FERC ¶ 61,305, at 61,643. The Commission suggests upon reconsideration that its authority is unchanged whether "the central issue is viewed as one of cost allocation or as 'forced' purchases." 32 FERC ¶ 61,425, at 61,949. We do not interpret this comment as an assertion by FERC that it may, under any circumstances, force a purchase among nonaffiliates.

[76] 343 U.S. 414 (1952). *See also* discussion of *Nantahala Power & Light, supra* text at notes 63-65.

continuation and determine contract terms suitable to achieve that end:

> The Act gives the Commission ample statutory power to order Penn Water and Consolidated to continue their long-existing operational "practice" of integrating their power output. . . . In ordering such "practice" continued, the Commission was furthering the expressly declared policy of [section 206 of] the Act.[77]

This case provides a solid foundation for the Commission's authority to order a purchase or sale of power when, as here, such an order is consistent with the historical integration of a power pool or network.

This conclusion is further confirmed by the decision of this circuit in *Central Iowa Power Cooperative v. FERC*.[78] In that case, FERC approved a voluntary pooling agreement among some 31 electric systems. The petitioners therein complained that the agreement failed to provide services offered by pooling arrangements established among other electric systems. Because of the voluntary nature of pooling arrangements under section 202(a) of the FPA, the court held that FERC could not order an expansion of pool services merely upon a showing "that a particular pool does not offer the same range of services as another pool."[79] The court, however, went on to determine that FERC did have "specific responsibility in this proceeding to decide whether a particular voluntary pool agreement was unjust, unreasonable, or unduly dis-

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[77] *Id.* at 422-23. The Court specifically noted that the Commission's order was based on authority derived from section 206 of the FPA, and not from the underlying contract between the parties. *Id.* at 422.

[78] 606 F.2d 1156 (D.C. Cir. 1979).

[79] *Id.* at 1167 (quoting with approval the Decision of the Commission).

criminatory,"[80] and, in the event of such a finding, that FERC had authority to order expanded services:

> The Commission had authority . . . under section 206 of the Act . . . *to order changes in the limited scope of the Agreement, including the addition of pool services*, if, in the absence of such modifications, the Agreement presented "any rule, regulation, practice or contract [that was] unjust, unreasonable, unduly discriminatory or preferential."[81]

Having found that the agency may exercise authority under section 206 to modify an unlawful voluntary power pool arrangement negotiated by nonaffiliates, *a fortiori* we must conclude that FERC may intervene to reform an unlawful agreement made by affiliates in a fully integrated, commonly owned system.

The cases relied upon by the Arkansas-Missouri petitioners are easily distinguishable. In *Southern Co. Services, Inc.*,[82] Southern Company filed a contract with the Commission to increase sales to Florida Power & Light ("FP&L"). Seminole Electric Cooperative intervened in the proceeding and argued that FP&L should be required to purchase energy from it. Seminole was a stranger to the UPSA at issue in *Southern*, was not affiliated with either Southern or FP&L, and did not contend Southern's rates were unjust or unreasonable under the FPA. Given the entirely inapposite factual setting of *Southern*, FERC's refusal to reject the Southern-FP&L contract or to order FP&L to purchase power from Seminole is irrelevant to the present case.

The Arkansas-Missouri petitioners also maintain that *Otter Tail Power Co. v. FPC*,[83] establishes that compul-

[80] *Id.* at 1167 n.33.

[81] *Id.* at 1168 (emphasis supplied).

[82] 20 FERC ¶ 61,332 (1982).

[83] 473 F.2d 1253 (8th Cir. 1973).

sory purchases of power may be characterized as a compelled expansion of generating facilities, forbidden by section 202(b) of the Act. In that case, FERC ordered a utility to interconnect with a municipality and to assume the costs of the municipality's generating plant in exchange for energy from the plant. The court determined that this transaction forced the utility to assume beneficial ownership of the plant, *i.e.*, to enlarge its facilities. In the present case, FERC has ordered the operating companies to pay a certain percentage of the capacity costs of Grand Gulf—an entity constructed for system benefit and already within the beneficial ownership of the parent holding company, MSU. The Commission decision does not add any capacity to the MSU system. Nor does it modify the percentage of generating capability for which each company will ultimately bear responsibility under the 1982 System Agreement; it simply alters the composition of each individual company's share.

In relying on *Otter Tail Power*, the parties once again seek to ignore AP&L's role as an affiliated company in an historically integrated system and Grand Gulf's status as a system project. In the factual context of the instant case, the reallocation of capacity costs among the parties cannot be described as a compelled purchase of either power or additional generating facilities.

3. *Intrusion on State Jurisdiction*

The Arkansas-Missouri petitioners and the Mississippi Public Service Commission ("MPSC") separately contend that FERC's orders unlawfully interfere with the jurisdiction of the state regulatory authorities. We will treat the arguments individually.

a. *The Arkansas-Missouri Argument*

Section 201(a) of the FPA provides that FERC's regulation of interstate wholesale sales of electricity extends "only to those matters which are not subject to regulation

by the States." The petitioners assert that the FERC orders interfere with local authority over matters intended to be within the province of state regulators. They reason that FERC's cost allocation has such an extensive impact on the rate base in the state jurisdictions that it, in effect, removes regulation of retail rates and capacity construction from the hands of the state commissions. These assertions are unfounded. FERC has exercised its jurisdiction in order to regulate the sale of electricity at wholesale in interstate commerce in the context of exchanges within a multi-state power pool, an area exclusively subject to FERC control. The fact that FERC's assertion of jurisdiction has some impact on state regulation does not make it unlawful.

As the Supreme Court made clear in *Public Utilities Comm'n of Rhode Island v. Attleboro Steam & Electric Co.*,[84] the states are constitutionally prohibited from exercising jurisdiction over wholesale rates for electricity transmitted and sold in interstate commerce. In the absence of federal action. this holding created a regulatory gap. and Congress enacted Title II of the FPA to fill that gap and provide for federal authority over interstate wholesale rates:

> Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary . . . case-by-case analysis. This was done in the Power Act by making FPC jurisdiction plenary and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.[85]

This holding was confirmed in *Pacific Gas & Electric Co. v. State Energy Resources Conservation & Develop-*

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[84] 273 U.S. 83 (1927).

[85] *FPC v. Southern California Edison Co.*, 376 U.S. 205, 215-16 (1964).

ment Comm'n,[86] in which the Supreme Court observed that states have retained "their traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost, and other related state concerns" "[w]ith the exception of the broad authority of the . . . Federal Energy Regulatory Commission over the need for and pricing of electrical power transmitted in interstate commerce . . . ."[87]

[86] 461 U.S. 190 (1983).

[87] *Id.* at 205-06. The Arkansas parties accuse FERC of contravening the Supreme Court's decision in *Arkansas Electric Cooperative Corp. v. APSC,* 461 U.S. 375 (1983). In that case, the Court upheld state jurisdiction over the wholesale rates of a rural power cooperative, in part because the FPC had previously determined that it lacked jurisdiction to regulate these entities which fall under the supervision of the Rural Electrification Administration. The Court, therefore, rejected the old "bright line" between state and federal jurisdiction, *i.e.,* the distinction drawn between regulation of retail or wholesale rates under the commerce clause. Simultaneously, however, the Court emphasized that a new "bright line" between state and federal jurisdiction had been drawn by Congress in the FPA. We hold that the Commission's actions fall within a domain assigned to federal control by the FPA.

Petitioner Arkansas Industries accuses FERC of concluding that federal and state jurisdictions are overlapping and of performing a balancing of the relevant federal and state interests under the commerce clause—a course of action eschewed by the "bright line" test as articulated in *Arkansas Electric*—in its decision to allocate Grand Gulf. As detailed above, we have decided that FERC's allocation of Grand Gulf costs is within its exclusive authority over wholesale rates in interstate commerce under the FPA. The Commission's explicit sensitivity to state concerns in determining the extent to which it would exercise its authority to remedy the unlawfulness of the UPSA is not equivalent to an inquiry under the commerce clause to determine whether a state may regulate in this realm.

As explained above, there is no clash between state and federal jurisdiction in the instant case. FERC's allocation of Grand Gulf was simply an exercise of its authority to regulate wholesale rates in interstate commerce—an area within its exclusive jurisdiction.

The Arkansas-Missouri petitioners contend that the FERC orders deprive state commissions of their control over retail rates. The Supreme Court has recently confirmed that

> [o]nce FERC sets . . . a rate, a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable. A state must rather give effect to Congress's desire to give FERC plenary authority over interstate wholesale rates, and to ensure that the States do not interfere with this authority.[88]

Thus, once FERC permits a utility to charge a rate reflecting investment in a particular plant, a state commission may be obliged to reflect such an investment in the retail rate base. Under these circumstances, the petitioners argue, state regulatory authorities confronted with a FERC cost allocation will virtually lose control over retail rates.

In *Nantahala Power & Light*, the Supreme Court made clear that, in setting wholesale rates, the NCUC was required to give binding effect to the interstate wholesale rate that had been fixed by FERC. The Court further determined that the realm of preemption was "not limited to 'rates' *per se*" and stated:

> Here FERC's decision directly affects Nantahala's wholesale rates by determining the amount of low-cost power that it may obtain, and FERC required Nantahala's wholesale rate to be filed in accordance with that allocation. FERC's allocation of entitle-

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[88] *Nantahala Power & Light Co. v. Thornburg*, 54 U.S.L.W. at 4680.

> ment power is therefore presumptively entitled to more than the negligible weight given it by NCUC.[89]

Similarly, in the present case, the Commission's allocation of Grand Gulf's costs and capacity affects wholesale rates and, therefore, the state commissions may not "interfere" with FERC's "plenary authority."

Moreover, the petitioners' argument would apply to the costs embodied in any wholesale rate approved by FERC and, therefore, proves too much. In any wholesale rate proceeding, the state commissions may protect their interests, as here, by intervening and presenting evidence before the Commission, a neutral body. The main point here is that FERC plainly had authority to approve or reject the cost allocation pursuant to its jurisdiction over wholesale interstate rates despite its inevitable impact on retail rates.[90]

Moreover, when, as here, affiliated operating companies in an integrated regional system enter into agreements for wholesale power sales in interstate commerce which allocate costs, FERC jurisdiction has additional merits. As ALJ Head observed, "the Commission is perhaps in the best position to reach the most equitable result and to act in the public interest, rather than to be controlled by the necessarily parochial concerns of the States." [91] The basis of this conclusion has been discussed by FERC in another context:

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[89] *Id.*

[90] In *Northern States Power Co. v. Minnesota Public Utilities Comm'n,* 344 N.W.2d 374 (Minn.), *cert. denied,* 104 S. Ct. 3546 (1984), and *Northern States Power Co. v. Hagen,* 314 N.W.2d 32 (N.D. 1981), two state supreme courts determined that their respective state regulatory commissions had to accept and collect the allocated costs of an abandoned nuclear plant project in the retail rates charged for NSP Company power. We endorse the state courts' conclusion that FERC had authority to approve or reject the cost allocation.

[91] 30 FERC ¶ 63,030, at 65,151.

If State Commission A orders a change to be made in a wholesale rate filing, presumably because it would benefit the ratepayers in State A, then State Commission B might well retaliate by ordering a counter rate filing that would benefit the ratepayers in State B. . . . It was to protect against such competing local state interests that a Federal Commission was given jurisdiction to protect the national interest in transmission and sales for resale in interstate commerce.[92]

[92] *Western Massachusetts Electric Co.,* 23 FERC ¶ 61,025, at 61,064 (1983). Most recently, the Eighth Circuit spoke to a similar question in the same factual context involved in the instant case. In *Middle South Energy, Inc. v. APSC,* 593 F. Supp. 363 (E.D. Ark. 1984), *aff'd,* 772 F.2d 404 (8th Cir. 1985), *cert. denied,* 106 S. Ct. 884 (1986), the APSC sought to require AP&L to show cause why the UPSA and the other Grand Gulf allocation agreements were not void *ab initio* because the utility had failed to obtain the APSC's prior approval. The district court enjoined the inquiry, holding that it constituted a collateral challenge to the FERC proceedings and an intrusion into a preempted area. On appeal, the Eighth Circuit affirmed, but rested its decision on an alternative finding that APSC's inquiry was an unwarranted burden on interstate commerce. The Eighth Circuit's characterization of APSC's purpose is instructive and highlights the merit of federal regulation in the present case:

> The APSC seeks to cancel the Grand Gulf agreements ostensibly because they have not received the necessary state regulatory approval. Its apparent concern, which has been made abundantly plain in its orders and its arguments before the SEC and FERC, however, is the economic impact on Arkansas citizens caused by AP&L's participation in Grand Gulf. It seeks to deflect what it has estimated to be rate increases of more than $3.5 billion over the next ten years. Given free rein, the APSC would shift this burden to the citizens of Mississippi and Louisiana, citizens who are powerless to directly influence Arkansas' internal affairs.

772 F.2d at 416-17 (footnote omitted).

This same reasoning applies with equal force to a cost allocation among affiliates who exchange power at wholesale in interstate commerce.[93]

b. *The Mississippi Argument*

The MPSC argues that the Commission's orders unlawfully disregard the considerations upon which that state agency relied in certificating construction of Grand Gulf in Mississippi. We find the Commission's analysis and rejection of this argument entirely correct.

MPSC asserts that the utilization of any allocation procedure other than that accepted by it in the Grand Gulf certification proceedings would impermissibly usurp its certification authority. As the Commission found, this assertion is incorrect for several reasons. First, as has been detailed above, state regulatory authorities, in-

[93] The Arkansas-Missouri petitioners further maintain that FERC's orders usurp state jurisdiction by imposing costs on AP&L for capacity it does not need. This argument appears ludicrous in light of the integrated planning and construction of generating capacity on a system-wide basis. Moreover, none of the operating companies seek Grand Gulf capacity at the present time.

Equally fallacious is the APSC's argument that FERC's orders have unlawfully "remove[d] low cost facilities from AP&L by forcing a sale from those facilities to consumers in Louisiana and Mississippi." APSC Brief at 41. The reallocation of Grand Gulf simply adjusts AP&L's share of MSU's generation capacity costs—costs incurred jointly by the system.

APSC also asserts that it issued certifications for Arkansas' nuclear and coal plants based upon its perception of the needs of AP&L's customers and that it carefully supervised construction of these plants to insure low costs. Hence, the state regulatory authority contends that it would be unfair to impose upon Arkansas generating capacity not subject to similar prior scrutiny. This argument, too, fails; AP&L's supporters are not free to ignore the historical integration of the MSU system and AP&L's continuous involvement and responsibility in planning generation capacity for that system.

cluding the MPSC, do not have authority, as a threshold matter, to approve any allocation of Grand Gulf's cost or capacity among the system operating companies. Such decisions were subject to review and approval by the Commission.

Moreover, the MPSC argument, which it quite properly characterizes as one of equitable estoppel, is untenable under the circumstances. As FERC correctly observed, the Commission itself made no representations to the MPSC; its hands could not be tied by the doctrine, particularly here where its application would lead to "an inequitable result." [94]

Finally, it is noteworthy that the MPSC "did not specifically approve any particular allocation or allocation methodology for Grand Gulf or establish any particular allocation or allocation methodology as a condition of the certificate." [95] This factual prerequisite to the application of the doctrine of equitable estoppel, too, is absent.

For all of these reasons, the MPSC's arguments were properly rejected by FERC.

4. *Intrusion on the SEC's Jurisdiction*

The Arkansas-Missouri petitioners contend that FERC has impermissibly infringed upon the authority of the SEC to regulate the MSU system as a registered holding company under the PUHCA.[96] They further maintain that, by statutory mandate, any conflict between the SEC's authority under the PUHCA and FERC's authority under the FPA must be resolved in favor of the

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[94] 30 FERC ¶ 63,030, at 65,166, *cited in* 31 FERC ¶ 61,305, at 61,645.

[95] 26 FERC ¶ 63,044, at 65,111-12. *See also* 30 FERC ¶ 63,030, at 65,166, *cited in* 31 FERC ¶ 61,305, at 61,645.

[96] 15 U.S.C. §§ 79 *et seq.* (1982).

former.[97] We find no inconsistency in the actions taken by FERC and the jurisdiction of the SEC.

The SEC has correctly explained the division of responsibility between itself and FERC:

> The jurisdiction of this Commission [the SEC] with respect to the availability agreement existed under Section 12(b) of the Act as to the indemnity obligations of the four operating companies to MSE and as to the indemnity that three of the companies gave to APL. *The contracts for the sale of electric energy among the subsidiaries of MSE* [*sic*] *are subject to the exclusive jurisdiction of FERC.* Generally a contract for sale of goods and services to an associate company is governed by Section 13(b) of the Act, but Section 2(a)(20), which defines "Sales contract," expressly excludes sale of "electric energy or natural or manufactured gas." [98]

The SEC thus explicitly acknowledged FERC's control over wholesale rates and sales among the operating companies and its statutory authority over the rates and rate-related terms of the UPSA.[99] Moreover, when the

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[97] *See* 16 U.S.C. § 825q (1982).

[98] *In the Matter of Middle South Utilities, Inc., Middle South Energy, Inc.*, SEC PUHCA Release No. 23,579, 32 SEC Docket 416, 419 n.15 (Jan. 23, 1985) (Memorandum Opinion and Order Authorizing Common Stock Sale and Acquisition and Denying Request for Hearing) (emphasis supplied).

[99] The SEC has also observed that

> [t]he operating subsidiaries in the Middle South system have been an integrated system since 1930. As an integrated system, the operating companies have been parties to a series of system agreements governing intercompany sales of electric energy, as well as the planning, construction and operation of generation and transmission facilities. *These agreements are regulated by* [*FERC*] *under the Federal Power Act.*

Id. at 417-18 (footnote omitted) (emphasis supplied).

SEC approved the Reallocation Agreement among the system operating companies,[100] it recognized that a rate schedule for the sale of energy would be filed with FERC —a schedule plainly subject to modification pursuant to FERC's authority under the FPA. The SEC itself perceives no conflict between its jurisdiction and that of FERC. Similarly, having determined that the allocation of Grand Gulf is well within FERC's authority over wholesale rates for electric energy in interstate commerce, we, too, have little trouble concluding that there is no conflict with SEC jurisdiction.

Nor do we find merit in the claim that FERC's action is at odds with the goals of the PUHCA. We agree that an important aim of the PUHCA was the elimination of control of some holding companies so that local utilities might be regulated by local authorities. However, the PUHCA itself permits holding companies to own subsidiary utilities when its purposes are best served by focusing on regional rather than state interests, so long as the effectiveness of regulation is not impeded.[101] The PUHCA permits the continued existence of a holding company if its operations are limited "to a single integrated public-utility system," [102] which is defined as follows:

> a system consisting of one or more units of generating plants and/or transmission lines and/or distributing facilities, whose utility assets, whether owned by one or more electric utility companies, are physically interconnected or capable of physical interconnection and which under normal conditions may be economically operated as a single interconnected and coordinated system confined in its operations to a single area or region, in one or more States, not

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[100] *Middle South Energy, Inc.*, SEC PUHCA Release No. 22,280 (Nov. 18, 1981).

[101] *See* 15 U.S.C. § 79k(b) (1982).

[102] *Id.*

> so large as to impair (considering the state of the art and the area or region affected) the advantages of localized management, efficient operation, and the effectiveness of regulation . . . .[103]

The SEC has determined that the MSU system constitutes an "integrated public-utility system."[104] Thus, the regional integration embodied in the structure of the MSU system was clearly contemplated by Congress when it enacted the PUHCA.

Moreover, in the PUHCA itself, Congress recognized "that affiliate power transactions 'are not susceptible of effective control by any State.'"[105] Transactions, such as this one, between affiliated power companies appear to be precisely the type of transactions that Congress sought to regulate by enactment of the Federal Power Act and the Public Utility Holding Company Act of 1935."[106]

5. *The Mobile-Sierra Doctrine*

The APSC maintains that FERC's orders disregard the *Mobile-Sierra* doctrine,[107] which requires the Commission to respect certain private contract rights in exercising its regulatory powers. We find that, in the instant case, this doctrine does not bar the exercise of FERC's power under section 206 of the FPA to reform

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[103] *Id.* § 79b(a)(29).

[104] *Middle South Utilities, Inc.*, 35 S.E.C. 1, 10 (1953).

[105] *State of Minnesota*, 344 N.W.2d at 382 n.17 (quoting 15 U.S.C. § 79a(a) (1982)).

[106] *Id.*

[107] This doctrine is based on the companion cases of *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

a practice or contract affecting a rate charged by a public utility for wholesale service in interstate commerce.

In the *Mobile* case, the Mobile Gas Service Corporation ("Mobile"), a natural gas distributor, had entered into a long-term contract with the United Gas Pipe Line Company ("United") to purchase gas for resale to an industrial customer, Ideal Cement Company ("Ideal"). Ideal had a reciprocal contract to buy the gas from Mobile. The Mobile-United agreement had been filed with the Commission and was part of United's filed schedule of rates. Subsequently, United, acting without the consent of Mobile, altered the rates specified in its contract with Mobile by filing with the Commission a new rate schedule purporting to increase the rate on gas sold to Mobile for resale to Ideal. Mobile challenged United's action, and the Supreme Court held that the Natural Gas Act does not permit natural gas companies to change their rate contracts by unilateral action.

Thereafter, in *Sierra*, the Court applied its holding in *Mobile* to cases arising under the FPA. Thus, neither the filing of a new rate nor a finding that it is reasonable may abrogate a utility's contract with a distributor. "Together, the two cases make it crystal clear that a heavy burden must be met before a customer who has negotiated a fixed-price contract can be deprived against his will of the benefits of his bargain." [108]

APSC suggests that, in reforming the UPSA, FERC has snatched from AP&L the favorable result of its contractual escape from responsibility for Grand Gulf in contravention of the *Mobile-Sierra* holdings. We disagree. Initially, we note that the UPSA itself expressly permits unilateral changes in the contract by MSE:

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[108] *Town of Norwood v. FERC,* 587 F.2d 1306, 1310 (D.C. Cir. 1978).

> Nothing contained herein shall be construed as affecting in any way the right of MSE to unilaterally make application to FERC for a change in the rates contained herein or any other term or condition of this Agreement under Section 205 of the Federal Power Act and pursuant to FERC Rules and Regulations promulgated thereunder.[109]

Moreover, the UPSA makes no mention of any restriction on the Commission's authority to reform agreements under section 205 or section 206 of the FPA.[110] This circuit has made it clear that parties may agree to unilateral rate filings [111] and that parties may agree to "leave unaffected" the Commission's power to replace rates, and terms affecting rates, that are either contrary to the public interest or unjust, unreasonable, unduly discriminatory or preferential to the detriment of the contracting parties.[112] The signatories to the UPSA elected to

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[109] 616-R. 2982, I J.A. 246.

[110] In fact, the record suggests that the parties contemplated FERC review of the terms of the UPSA. *See* Reallocation Agreement, July 28, 1981. 616-R. 3275, I J.A. 268 ("2. An agreement between LP&L, MSE, MP&L and NOPSI will be executed in form for filing with the Federal Energy Regulatory Commission in accordance with Part 35 of the Commission's Regulations establishing the terms, conditions and rates for the sale of capacity and energy from MSE to LP&L, MP&L and NOPSI. . . . 7. The effectiveness of this Agreement is subject to the receipt of all necessary regulatory approvals.").

[111] *See Papago Tribal Utility Authority v. FERC*, 723 F.2d 950, 953 (D.C. Cir. 1983), *cert. denied*, 104 S. Ct. 3511 (1984); *Kansas Cities v. FERC*, 723 F.2d 82, 87 (D.C. Cir. 1983).

[112] *Papago Tribal Utility Authority*, 723 F.2d at 953. The APSC incorrectly suggests the Supreme Court's holding in *Sierra* made the public interest standard the sole criteria for contract revision in section 205 or section 206 proceedings.

permit unilateral rate filings and not to restrict the Commission's power.[113] The parties' bargain itself contemplates the Commission's review, and potential reform of their agreement; the *Mobile-Sierra* doctrine requires no more.[114]

Finally, even if the contracts fall within the scope of the *Mobile-Sierra* decisions, the Supreme Court has emphasized that the relevant agency, here FERC, may always reform a contract found to be "unlawful" or "contrary to the public interest," *i.e.*, that "contracts remain fully subject to the paramount power of the Commission to modify them when necessary in the public interest." [115] The Court stated in *Sierra* that the Commission "has undoubted power under § 206(a) to prescribe a change in contract rates whenever it determines such rates to be unlawful" [116] and indicated three circumstances under which the Commission might conclude that a rate or a contract term affecting a rate could be found

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In fact, as this court has made clear, either the interest of the public *or* the interest of the parties in nondiscriminatory rates will suffice to justify the *Commission's* decision to reform rates, *id.* at 954 n.5, so long as the parties' contract does not eliminate the Commission's authority over discrimination or preference that operates only against the signatories. Such discrimination may be waived "up to the point where it produces some independent harm to the public interest," *id.* at 953 n.4, but no such waiver took place in the instant case.

113 "[C]ourts and the Commission have almost universally construed contractual references to future rate changes to authorize § 206 proceedings with a just-and-reasonable standard of proof." *Kansas Cities*, 723 F.2d at 88.

114 *See Richmond Power & Light v. FPC*, 481 F.2d 490, 493 (D.C. Cir.) (describing the *Mobile-Sierra* doctrine as "refreshingly simple: . . . Rate filings consistent with contractual obligations are valid; rate filings inconsistent with contractual obligations are invalid."), *cert. denied*, 414 U.S. 1068 (1973).

115 *Mobile*, 350 U.S. at 344.

116 *Sierra*, 350 U.S. at 353.

contrary to the public interest and therefore subject to revision: "where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory." [117] Here FERC expressly adopted the findings of ALJ Liebman who found the level of discrimination in the UPSA "profound" and agreed that its impact on customers in Louisiana and Mississippi would be "dramatic[]." [118] The Commission's specific determination of unlawfulness provides the "unequivocal public necessity" [119] for reformation of the UPSA under section 206 of the FPA.

For each of the foregoing reasons, the *Mobile-Sierra* doctrine does not preclude FERC's actions in the instant case.

C. *Conclusion*

For all of the foregoing reasons, we reject petitioners' principal contentions with respect to FERC's jurisdiction. We have also considered all other arguments suggesting that the Commission is without jurisdiction in this case, and we find them to be without merit. The Federal Power Act clearly provides FERC with authority to issue the orders here in question. We now turn to the merits of this case.

III. MERITS

Petitioners challenge FERC's decision to reject the Unit Power Sales Agreement and to equalize nuclear capacity among the MSU operating companies. In the process, many advocate adoption of a particular, alternate allocation. We reject these challenges because we conclude that FERC's action was both rational and within

[117] *Id.* at 355.

[118] 26 FERC ¶ 63,044 at 65,108 & 65,104.

[119] *Permian Basin Area Rate Cases,* 390 U.S. 747, 822 (1968).

the Commission's range of discretion to remedy unduly discriminatory rates. We first examine the workings of the UPSA and the 1982 System Agreement and then review the evidentiary basis for FERC's determination that the Agreements as filed were unduly discriminatory. We then address petitioners' claims that FERC was required to adopt a remedy other than the one it chose. Finally, we consider several remaining issues such as Commissioner Richard's refusal to recuse himself and FERC's refusal to reopen and update the record.

A.

Under section 206 of the Federal Power Act ("FPA"), FERC must determine whether an agreement as filed is "unjust, unreasonable, unduly discriminatory or preferential." 16 U.S.C. § 824e(a) (1982). If the agreement is just and reasonable, then it is approved as filed. If, on the other hand, the agreement is unduly discriminatory, then FERC is required to "determine the just and reasonable . . . contract to be thereafter observed and in force, and shall fix the same by order." *Id.*

In this case, FERC reviewed "two initial decisions in dockets which are not consolidated but which have overlapping issues concerning the appropriate allocation of capacity costs incurred on the . . . (MSU) system." 31 F.E.R.C. (CCH) at 61,631. Thus, FERC considered whether the UPSA and the 1982 System Agreement, taken together, were just and reasonable.

To understand the Commission's decision, it is necessary to examine the workings of the UPSA and the System Agreement in detail. The UPSA resulted from negotiations among the four operating companies and MSE in 1979. These negotiations produced the 1981 Reallocation Agreement in which the companies agreed that all Grand Gulf power would be purchased by LP&L, MP&L and NOPSI in definite percentage shares. AP&L relinquished all interest in Grand Gulf, and the other operating com-

panies agreed to indemnify and hold AP&L harmless for its obligations to lenders under the 1974 Availability Agreement.

Pursuant to the Reallocation Agreement, the parties executed the UPSA in June 1982 to be filed with FERC. The UPSA provides in pertinent part:

> 1.2 The Purchasers shall, subject to the terms and conditions of this Agreement, be entitled to receive all of the Power which shall be available to MSE at the Project in accordance with their respective Entitlement Percentages. The Entitlement Percentages are as follows:

	Entitlement Percentages Unit No. 1
LP&L	38.57%
MP&L	31.63%
NOPSI	29.80%
	100.00%

26 F.E.R.C. (CCH) at 65,097. The UPSA further provides that LP&L, MP&L and NOPSI shall pay MSE the same proportionate shares of the total capital and operating costs of the Grand Gulf unit. *Id.* Thus, the UPSA allocates Grand Gulf *capacity* and *energy* in identical shares.

Meanwhile, in April 1982, MSU filed the 1982 System Agreement with FERC to create a new rate schedule for the generation and consumption of the System's energy. A critical aspect of the 1982 System Agreement, for our purposes, is that it does not apply to Grand Gulf. That is, it assumes the existence of the UPSA and its allocation of Grand Gulf capacity and energy. Thus, the 1982 System Agreement may be read and applied properly only by recalling the Grand Gulf allocations fixed by the UPSA.

Under the 1982 System Agreement, capacity and energy costs are allocated separately. As for energy, each com-

pany is entitled to first call on the lowest cost energy generated by the plants located within its service area (and by Grand Gulf up to its UPSA percentage entitlement). The energy generated by a company's plants in excess of that company's demand goes into a pool of energy available to companies whose plants produce less energy than they demand. Such companies may purchase the lowest cost energy available in the pool.

The 1982 System Agreement also establishes a formula to equalize roughly the costs of *capacity* to generate energy. This is achieved by equalizing capacity among the operating companies with corresponding capacity equalization payments. Companies that are "long" on capacity—*i.e.*, those whose percentage of total System capacity exceeds their percentage of total System demand—contribute their excess capacity to "short" companies—*i.e.*, companies whose percentage of total System capacity is less than their percentage of total System demand. In return, the "short" companies make capacity equalization payments to the "long" companies. Under the 1982 System Agreement, these payments are based on the investment costs of "intermediate" oil and gas fired generation facilities, which are much lower than the investment costs of newer coal and nuclear units. In determining whether, and to what extent, a company is long or short, the System considers not only the capacity of units located in that company's service area, but also the share of Grand Gulf capacity to which that company is entitled under the UPSA.

The operating companies intended to roughly equalize the System's capacity costs among themselves by executing the UPSA and the 1982 System Agreement. And, indeed, *at the time they were negotiated*, these agreements appeared to achieve that objective. When the UPSA was negotiated in 1979, Grand Gulf capacity appeared to be a good buy. The initial cost estimate for building *both* Grand Gulf units was $1.3 billion; by the

time the first unit began operations in 1985, however, the final cost for that unit alone was $2.7 billion. It seems unlikely that, in 1979, the companies could have foreseen that the cost of completing Grand Gulf would quadruple because of the lengthy regulatory delays that would occur in the aftermath of the Three Mile Island accident. The System Agreement's formula for roughly equalizing capacity costs among the companies also appeared reasonable when negotiated. Capacity equalization payments were based on the costs of oil and gas fired units, rather than the more costly nuclear and coal fired units. Historically, a company's ability to construct oil and gas fired units depended on the existence of sufficient natural resources within its service area. By contrast, the ability to build coal and particularly nuclear units was less restricted. Thus, when the System decided to shift to coal and nuclear capacity, each of the operating companies was assigned to build nuclear capacity: AP&L was assigned ANO I & II; LP&L was assigned Waterford III; MP&L was assigned Grand Gulf I; and NOPSI was assigned Grand Gulf II. The cost of nuclear capacity was assumed to be roughly equivalent. Thus, each company would share in the cost of the older oil and gas capacity—either by having constructed it or by making capacity equalization payments—and each company would share in the cost of the System's newer capacity—by constructing nuclear and/or coal fired units.

By the time the Commission reviewed the UPSA and the System Agreement, however, conditions had changed radically. Though AP&L had successfully completed the ANO units without substantial cost overruns, *see* 31 F.E.R.C. (CCH) at 61,669 n.17, the cost of constructing Grand Gulf I and Waterford III approached three to four times original estimates. As ALJ Liebman recognized, "[d]isparate rates are legitimate under section 205(b) of the FPA if sufficient factual bases exist to justify the difference." 26 F.E.R.C. (CCH) at 65,106 (*citing Metropolitan Edison Co.* v. *FERC*, 595 F.2d 851, 857, 858

(D.C. Cir. 1979)). Upon reviewing the nature and operation of the MSU System, Judge Liebman concluded that the facts were insufficient to outweigh "the profound undue discrimination caused by [the UPSA] allocation." *Id.* at 65,108. The Commission affirmed, concluding that "the 1982 System Agreement and the UPSA, as filed, together will [not] achieve proper cost allocation," and that "the 1982 System Agreement in conjunction with Judge Liebman's allocation of nuclear capacity will achieve just and reasonable results." 31 F.E.R.C. (CCH) at 61,655.

B.

The Commission based its decision primarily upon two findings: (1) "the fact that all Middle South System nuclear units have been planned to meet overall System needs and objectives," and (2) "the unforeseen problems unique to constructing nuclear units." 31 F.E.R.C. (CCH) at 61,655 (footnote omitted). The Commission's first finding is more than adequately supported by the record. The Commission began by discussing the composition of, and key role performed by, the System Operating Committee. The Operating Committee is composed of five members: one representative from each of the four operating companies and one from the System's wholly-owned service company, Middle South Services, Inc. ("MSS"). *See* 31 F.E.R.C. (CCH) at 61,646; 30 F.E.R.C. (CCH) at 65,143. The Commission undertook a thorough review of the record testimony of current and former System executives, *see* 31 F.E.R.C. (CCH) at 61,646-48, as well as various sets of minutes of the System Operating Committee from 1961 to 1980, *see id.* at 61,648-50. This evidence amply supports the Commission's conclusion that although individual operating companies were intimately involved in the planning stages of new generation units and sought to promote their own interests, "the Operating Committee nevertheless made the major decisions concerning general timing, location and size of plant additions, in view of the overall needs of the system,

while accommodating individual company needs wherever possible." *Id.* at 61,650. For example, Mr. Trumps, an MSS official, testified that "generation planning has been done on a systemwide basis, but with due consideration of the needs of the individual companies as to the location of new facilities." *Id.* at 61,647. Mr. Trumps also testified that under the 1973 System Agreement, an individual operating company could not block an Operating Committee decision since that body acted by two-thirds vote, and that the 1982 System Agreement further strengthened the Committee's position by authorizing decisions to be made by majority vote. *See id.* at 61,651.

In making its findings about the System's planning and operations, FERC expressly rejected ALJ Head's contrary findings as unsupported by the evidence. First, the Commission rejected Judge Head's conclusion that there is "a pattern of autonomy on the part of the individual operating companies, particularly as to specific plant site locations, fuel and financing." 30 F.E.R.C. (CCH) at 65,168. The Commission acknowledged that the operating companies "exercise[] their authority to decide details such as specific location, timing, and sizing of [an assigned] unit," 31 F.E.R.C. (CCH) at 61,650, but rightly concluded that this fact does not affect the finding that "decisions on the MSU System are made based on an overall *System* plan and primarily for the System as a whole," *id.* (emphasis in original).

Second, and more important for our purposes, the Commission rejected ALJ Head's determination that Grand Gulf is "an anomaly to the regular planning and construction of generating facilities by the operating companies of the Middle South system." 30 F.E.R.C. (CCH) at 65,172. Again, the Commission's conclusion is supported by the record. Relying on the testimony of Mr. Lupberger, an officer of MSU, MSE and MSS, the Commission began by recalling that in the late 1960's and early 1970's, the System decided to change its fuel mix

by shifting away from oil and gas generation in favor of nuclear and coal capacity. *See* 31 F.E.R.C. (CCH) at 61,651. Pursuant to that decision, AP&L was assigned to build the ANO units and MP&L was assigned to construct Grand Gulf I. After reviewing the relevant testimony, FERC concluded that "[t]he evidence supports a finding that the Grand Gulf units were originally planned in the same manner as the other nuclear units, *i.e.*, to meet MP&L's needs, to meet System needs, and to meet the System goal of diversifying fuel mix." 31 F.E.R.C. (CCH) at 61,653. The Commission recognized that the way in which Grand Gulf had to be financed, *see supra* pp. 17-18, resulted in differences between Grand Gulf and other system units, all related to the fact that MSE, rather than an individual operating company, owns and operates the plant. *See id.* But, as FERC correctly observed, these differences "arose solely from the fact that MP&L became unable to finance the Grand Gulf units on its own. They do not contradict the fact that Grand Gulf 1 and 2 were planned in the same manner as the other nuclear units on the system." *Id.* at 61,653-54. Indeed, Mr. Lupberger's testimony was that the system employed the same general process in deciding to build Grand Gulf as it did in deciding to build the ANO units. *See id.* at 61,654.

Having determined that "all Middle South System nuclear units have been planned to meet overall System needs and objectives," 31 F.E.R.C. (CCH) at 61,655, the Commission's conclusion that the UPSA and the 1982 System Agreement, as filed, were unduly discriminatory follows almost as a matter of course. Under the Agreements as filed, the cost of nuclear capacity varied widely from company to company. For example, the cost to AP&L for its 1694 megawatts of nuclear capacity was $900 million, while the cost to LP&L for 1538 megawatts was $3.4 billion, approximately four times as much. *See* 26 F.E.R.C. (CCH) at 65,107. Similarly, the cost to MP&L for 356 megawatts and to NOPSI for 335 mega-

watts was $800 million and $700 million, respectively, while AP&L received 1694 megawatts, approximately five times the capacity of either, for just $900 million. *See id.* As already discussed, the 1982 System Agreement's provision for capacity equalization payments does little, if anything, to reduce these vast nuclear capacity cost disparities. That is because AP&L is currently a "long" company, *see* 30 F.E.R.C. (CCH) at 65,166, and, in any event, capacity equalization payments are based on the costs of oil and gas fired units rather than more costly nuclear units such as Grand Gulf and Waterford III. Given the degree of integration on the MSU System, FERC could properly conclude that the tremendous disparities in nuclear capacity costs among the operating companies disrupt the System's historical pattern of roughly equalizing capacity costs and thus constitute undue discrimination under section 206 of the Federal Power Act.

The second finding upon which the Commission's decision rests—the existence of "unforeseen problems unique to constructing nuclear units," 31 F.E.R.C. (CCH) at 61,655—relates primarily to FERC's choice of means to remedy the undue discrimination on the system. Petitioners do not seriously dispute the existence of this finding; rather, they challenge the use to which it was put by the Commission. For example, the Arkansas-Missouri parties argue that FERC erred by considering facts and circumstances that arose after the execution of the UPSA in evaluating the reasonableness of that agreement. Rather, they assert that the Commission could do no more than "examin[e] the factual circumstances that prevailed at the time the UPSA was formulated in 1979-80." Brief of Petitioners Arkansas Public Service Commission, Missouri Public Service Commission, Arkansas-Missouri Congressional Delegation and State of Arkansas ("Arkansas-Missouri Pet. Br.") at 66; *accord* Brief for Petitioner Arkansas Power & Light Company ("AP&L Pet. Br.") at

45. We find this contention to be completely without merit.

Under the FPA, the Commission has a statutory duty to reform unlawful rates and establish just and reasonable ones, *see* 16 U.S.C. § 824e(a) (1982), and a statutory right to order production of, and to examine, "all accounts, records, and memoranda of licensees and public utilities," *id.* § 825(b), in performing that duty. This, in effect, was the Commission's response on rehearing: "The salient issue here is not whether the agreement was reasonable when made, or whether it met the System objectives at the time it was made. Rather, the principal inquiry is whether the allocation is appropriate based on the evidentiary record that was subsequently developed." 32 F.E.R.C. (CCH) at 61,957.

The Arkansas-Missouri parties appear to ignore this rationale and argue simply that FERC's evaluation of the UPSA in light of subsequent events conflicts with prior Commission precedent. *See* Arkansas-Missouri Pet. Br. at 67-68; AP&L Pet. Br. at 46-48. The cited cases are inapposite to the Commission's review of the UPSA. They establish only that the *prudence* of power supply arrangements and generation construction activities must be evaluated on the basis of circumstances prevailing at the time the activity was undertaken, and are thus limited to "prudence review"—examinations of utilities' decisions to incur costs. The Commission's inquiry is quite distinct. A system's allocation of nuclear capacity costs may not be imprudent on the part of the parties at the time they agree to incur them, but might nevertheless result in present undue discrimination. Accordingly, the cases present no bar to the Commission's reliance on the record to perform its statutory duty under section 206 of the FPA.

AP&L advances an additional argument against the Commission's second finding: "there is no substantial evidence of record put forth by the agency to support its

conclusion that the alleged problems were 'unforeseen.'" AP&L Pet. Br. at 45-46. Besides erroneously placing the burden of proof on the Commission, *see San Luis Obispo Mothers for Peace* v. *NRC*, 789 F.2d 26, 37 (D.C. Cir.) (en banc) (Commission's failure to "include citations to specific pages of the record . . . provides no basis for overturning the Commission's decision"), *cert. denied*, 107 S. Ct. 330 (1986), this objection is simply irrelevant. Even if we assume that the problems were foreseen when the UPSA was negotiated and that the parties *intentionally* entered into an unduly discriminatory agreement, the Commission's duty to reject the agreement as filed would not be diminished.

The Commission's second finding supports the Commission's choice of means to remedy the undue discrimination created by the UPSA and the 1982 System Agreement. That choice was to adopt ALJ Liebman's allocation of Grand Gulf and approve the 1982 System Agreement as filed. We hold that this choice was within the Commission's discretion to remedy the undue discrimination it identified on the System. We first examine the Commission's remedy in more detail and then consider the various petitioners' objections and alternate proposals.

The Commission allocated Grand Gulf responsibility as follows:

AP&L	36%
LP&L	14%
MP&L	33%
NOPSI	17%

See 31 F.E.R.C. (CCH) at 61,633. The effect of this allocation is "not just to allocate Grand Gulf costs, but to allocate the costs of all nuclear capacity on the MSU system." *Id.* This can be seen by following the steps necessary to arrive at this allocation. The System's total nuclear capacity costs are determined by summing the investment costs of all nuclear units on the System, ANO I & II, Waterford III and Grand Gulf. Multiplying this

figure by each company's relative share of total system demand yields each company's total cost responsibility in dollars. The amount of each company's prior nuclear investment costs is then subtracted to yield each company's Grand Gulf cost responsibility. Finally, these figures are divided by Grand Gulf's total investment cost to yield the percentage of Grand Gulf capacity for which each company is responsible. *See* 31 F.E.R.C. (CCH) at 61,655. "The result of this allocation of Grand Gulf is to give each operating company a share of the cost of nuclear capacity roughly proportionate to that company's relative share of system demand . . . ." 26 F.E.R.C. (CCH) at 65,109. The Commission's rationale for adopting this allocation is considered in the context of the various objections and alternate allocations advanced by the petitioners.

C.

Petitioners advance numerous arguments in opposition to the Commission's decision and propose various alternate allocations. We address these arguments in the context of reviewing each proposed alternate allocation.

1. *The UPSA and the 1982 System Agreement*

AP&L and the Arkansas-Missouri parties advocate approval of the UPSA and the 1982 System Agreement as filed. In so doing, they attack the Commission's decision on several grounds. We have already considered and rejected two of these grounds in the preceding section. *See supra* pp. 69-72. The remaining grounds are considered here.

First, AP&L argues that in reforming the UPSA, "the FERC failed to give weight to the Congressional policy favoring voluntary power pooling agreements by 'cavalierly disregarding' the reasonableness of the specific agreements that were filed with the agency." AP&L Pet. Br. at 41 (*quoting ANR Pipeline Co.* v. *FERC*, 771 F.2d 507, 519 (D.C. Cir. 1985)). While it is true that sec-

tion 202(a) of the FPA seeks to encourage voluntary power pooling transactions, *see* 16 U.S.C. § 824a(a) (1982). AP&L's argument is no more than an attack on the Commission's finding that the agreements as filed are unduly discriminatory. But we have already held that that finding is virtually inescapable, given the record in this case, *see supra* pp. 68-69, and we reject any suggestion that the FPA's policy to encourage voluntary power pooling agreements could override the Commission's specific obligation in section 205 of that Act to reject such agreements if found to be "unjust, unreasonable, unduly discriminatory or preferential." 16 U.S.C. § 824e(a) (1982).

Second, the Arkansas-Missouri parties assert that the Commission's decision is "inconsistent with the Commission's own established precedent in *Nantahala Power & Light Company*, Opinions Nos. 139 and 139-A, 19 FERC (CCH) ¶ 61,152 (1982) and 20 FERC (CCH) ¶ 61,430 (1982), *aff'd*, 727 F.2d 1342 (4th Cir. 1984), and *Georgia Power Company*, Opinion No. 711, 52 FPC 1343 (1974), *aff'd*, Opinion No. 711-A, 53 FPC 1103 (1975)." Arkansas-Missouri Pet. Br. at 54. Though these cases involve Commission refusals to equalize costs, they provide no support for petitioners in this case.

Georgia Power involved a challenge to Georgia Power's reliance on its own generation and transmission costs to establish its cost of service. The challenger argued that Georgia Power was part of an integrated electric utility system whose production costs should be allocated to its members on a system, rather than individual company, basis. Finding that the existing allocation was not unjust and unreasonable, the Commission declined to order a "rolled-in" or equalized cost allocation. Petitioners' argument ignores the fact that the FPC found no undue discrimination. The case is distinguishable on that basis alone. Moreover, the *Georgia Power* Commission suggested that a case involving companies' reliance on "large

multi-company generating units which are remote from their service areas" might necessitate some form of cost equalization. *See* 52 F.P.C. at 1349. Grand Gulf is such a unit. Thus, we hold that *Georgia Power*'s refusal to equalize costs in the absence of undue discrimination does not apply where, as here, the Commission found such discrimination in the presence of a multistage generating unit.

Nantahala involved an agreement between Nantahala Power & Light Co. and Tapoco, both wholly-owned subsidiaries of Alcoa, apportioning the capacity and energy which both companies were jointly entitled to receive from the Tennessee Valley Authority. That entitlement arose from a series of agreements among TVA, Alcoa, Nantahala and Tapoco under which Nantahala and Tapoco turned over land and generating facilities to TVA for development of the Fontana Dam in exchange for capacity and energy entitlements. The Commission found the apportionment agreement between Nantahala and Tapoco to be unfair. Though the Commisison declined to order full cost equalization, it increased Nantahala's entitlement to remedy the unfairness. The Commission's decision was based, in part, upon its conclusion that the two companies do *not* operate as an integrated system. *See* 19 F.E.R.C. (CCH) at 61,277. This conclusion was affirmed by the Fourth Circuit as based on substantial evidence. *See Nantahala Power & Light Co.* v. *FERC*, 727 F.2d 1342, 1348 (4th Cir. 1984).

In the case at bar, the Commission's review of the evidence led it to reach precisely the opposite conclusion—that the MSU system is highly integrated. That determination is supported by substantial evidence. *See supra* pp. 66-68. Moreover, the Commission has *not* ordered full production costs, or even nuclear production cost equalization in this case. Rather, as in *Nantahala*, it has ordered a more limited remedy designed only to cure the undue

discrimination found. Thus, petitioners' argument that the Commission went too far in this case is without merit.

Third, AP&L argues that the energy from its "less costly base load generation is displaced from AP&L's usage, to become 'exchange energy' and be sold into the pool for the benefit of the other operating companies." AP&L Pet. Br. at 50. This argument is simply wrong. Under the 1982 System Agreement, AP&L is entitled to first call on its own lowest cost energy, whatever the source. Thus, if ANO I & II produce AP&L's lowest cost energy and AP&L's demand exceeds the amount produced, then AP&L will retain all of the benefits of the ANO units regardless of its Grand Gulf allocation. If anything, more expensive, not less expensive, energy will be displaced. AP&L's real complaint is that it must pay its equitable share of Grand Gulf's *capacity* costs.

Fourth, AP&L argues that the Commission's decision compels it "to pay more for nuclear capacity than is justified by [its] actual ownership costs, and at the same time allows the other operating companies to pay less for nuclear capacity than their actual ownership costs." AP&L Pet. Br. at 55-56 (footnote omitted). This argument is difficult to understand. The premise seems to be that AP&L's "actual ownership costs" are only those associated with ANO I & II, while the other companies' include the costs of Grand Gulf. The premise is incorrect. Under the Commission's allocation, each company is responsible for the costs of its own nuclear units as well as its share of Grand Gulf. AP&L's argument is really that it should pay for none of the costs associated with Grand Gulf—the situation under the UPSA as filed. But, as we have already held, FERC correctly found that the UPSA allocation results in unlawful discrimination.

In short, AP&L and the Arkansas-Missouri parties have advanced no persuasive argument against the Commission's decision to reject the UPSA as filed.

2. *ALJ Head's Allocation*

Petitioners City of New Orleans, Mississippi Industries, MP&L, and Representative Webb Franklin, and intervenor Representative Wayne Dowdy support the Commission's finding of undue discrimination, but argue that the Commission erred in deciding to equalize all nuclear capacity costs. Rather, they assert that the Commission should have adopted ALJ Head's solution of equalizing only the investment costs associated with Grand Gulf. *See* Consolidated Brief of Petitioners Mississippi Industries, Mississippi Power & Light Company, and Representative Webb Franklin, and Intervenor Representative Wayne Dowdy ("Consolidated Pet. Br.") at 60-61; Brief of Petitioner City of New Orleans, Louisiana ("New Orleans Pet. Br.") at 48-50.

Putting aside for the moment these petitioners' arguments *against* the allocation ordered by FERC, we have little difficulty affirming FERC's rejection of Judge Head's solution. That solution rests on Judge Head's finding that Grand Gulf is an anomaly on the MSU System—the only facility planned and constructed for the benefit of the system as a whole. *See* 30 F.E.R.C. (CCH) at 65,170-72. FERC expressly rejected this finding, concluding instead that Grand Gulf was "planned in the same manner as the other nuclear units on the System." 31 F.E.R.C. (CCH) at 61,654. Thus, Judge Head's solution is viable only if we conclude that the Commission's findings concerning the integration of the MSU System and the status of the Grand Gulf unit are not based on substantial evidence. We have already concluded that they are. *See supra* pp. 66-68.

In advocating adoption of Judge Head's solution, petitioners rely primarily on three arguments against FERC's chosen allocation. First, they assert that the Commission's decision irrationally allocates 33% of Grand Gulf to MP&L, an increase over the 31.63% allocated to MP&L

under the unduly discriminatory UPSA. Second, they argue that FERC did not adequately explain why it focused on nuclear but not coal facilities in equalizing capacity costs. Third, they assert that MP&L and NOPSI receive less nuclear capacity per nuclear investment dollar than does AP&L. As explained below, we find that none of the arguments advanced by these petitioners requires reversal of the Commission's decision.

Petitioners' first objection is that "[t]he Commission failed to reconcile its allocation scheme imposing 33 percent of Grand Gulf costs on Mississippi with the finding that a 31.63 percent allocation was detrimental and unjustified." Consolidated Pet. Br. at 39. The argument is that because the UPSA was found to be unduly discriminatory, an allocation to MP&L greater than that found in the UPSA necessarily must be unlawful. The argument misconstrues the nature of the statutory inquiry. The question is whether the agreement is unduly discriminatory or preferential. Thus, there is no inconsistency in the Commission's determination that the UPSA's allocation of 31.63% of Grand Gulf to MP&L and 0% to AP&L is unduly discriminatory but that a 33% allocation to MP&L and a 36% allocation to AP&L is not. That is because a party claiming discrimination, by definition, objects only to his treatment as compared to that of other similarly situated parties. Thus, the reasonableness of the Commission's allocation may be judged only by examining the relative impact on the four operating companies and the degree to which they are similarly situated.

Petitioners' second argument is no more availing. They assert that "the system's planned shift to primary reliance on coal and nuclear generation . . . plainly does not support focusing exclusively on nuclear generation and excluding coal-fired baseload units from that formula." Consolidated Pet. Br. at 45-46; *accord* New Orleans Pet. Br. at 43. This argument is misleading. While the Sys-

tem's move toward coal and nuclear facilities might support equalization of the capacity costs of both coal and nuclear units, it does not *preclude* FERC's decision to equalize only the investment costs of the nuclear units. Petitioners' argument ignores the Commission's explicit finding that the unforeseen problems that led to dramatic cost overruns were "unique to constructing nuclear units." 31 F.E.R.C. (CCH) at 61,655 (footnote omitted). In this circumstance, we find that the Commission's focus on nuclear but not coal units was rational.

Petitioners argue further that "[t]o the extent that unexpectedly high costs of [nuclear] facilities support special allocation treatment, the stated reason supports only a grouping of Grand Gulf 1 and Waterford 3." New Orleans Pet. Br. at 44; *see* Consolidated Pet. Br. at 46-47. They argue that to include the ANO units but not the coal units was arbitrary and capricious since the investment costs of the former are comparable to those of the latter. To be sure, this fact would have justified a Commission decision to equalize only the investment costs of Grand Gulf and Waterford III. (Interestingly, neither these petitioners nor any others have advanced this option here or below.) But, we conclude that the Commission also rationally could include the ANO units. Indeed, FERC decided to include them precisely because their investment costs were *not* comparable to those of the more recent nuclear units. The Commission decided to equalize the investments cost of all nuclear units because their widely divergent costs were due solely to the timing of their construction, *see* 32 F.E.R.C. (CCH) at 61,960-61, a reason insufficient to justify the differences.

Petitioners' third argument is that the Commission's allocation is itself unduly discriminatory because it allocates only the investment costs of nuclear capacity but not the benefits produced by that capacity. Thus, "MP&L must pay approximately 15 percent of the aggregate cost of nuclear capacity on the MSU system, but receives the

benefit of only 9.5 percent [(or 371 megawatts)] of that capacity." Consolidated Pet. Br. at 63. AP&L, on the other hand, is responsible for only 33% of the System's nuclear investment costs, but is entitled to first call on the energy produced by 2099 megawatts, or 53.5%, of that capacity. *See* 26 F.E.R.C. (CCH) at 65,109. In addition, LP&L pays for 44%, and NOPSI pays for 8%, of the System's nuclear capacity costs, but receive only 1262 megawatts (or 32%), and 191 megawatts (or 5%), of nuclear capacity, respectively. *See id.* The reason for these differences is that AP&L's nuclear capacity is made up of inexpensive ANO capacity as well as capacity from Grand Gulf; all other operating companies' nuclear capacity is composed entirely of expensive Grand Gulf and Waterford III capacity.

In our opinion, the Commission acted within its discretion in ordering equalization of nuclear investment costs without equalization of nuclear capacity. The Commission's allocation serves to restore a *rough* equalization of all System capacity costs among the operating companies. In view of the fact that such costs have never been precisely equalized on the System, FERC was required to do no more to remedy the undue discrimination it found. As the Commission emphasized on rehearing:

> What our decision purports to do is to eliminate *drastic* rate disparities at the wholesale rate level which are associated with units used for the mutual benefit of all companies, and to do so in a manner which disturbs the historical operation of the System as little as possible, and which allows the individual companies to retain as fully as possible the benefits of units they have financed and constructed. In other words, we have sought to achieve an equitable balance between the interests of the individual companies and the System as a whole, consistent with the System Agreement.

32 F.E.R.C. (CCH) at 61,959 (emphasis added).

Petitioners' argument is even less persuasive when it is recalled that these petitioners advocate adoption of

Judge Head's solution as just and reasonable. Judge Head's solution was to allocate only the costs and capacity of Grand Gulf in proportion to each company's relative share of System demand, without regard to prior nuclear investment. But under this scheme, MP&L's nuclear cost responsibility as a proportion of total System nuclear costs would still exceed its proportion of total System nuclear capacity. This is so because although AP&L would be allocated a greater share of Grand Gulf responsibility, it would still be able to reduce its *average* nuclear capacity costs, with capacity from its less expensive ANO units; MP&L's nuclear capacity, though smaller, would still consist entirely of expensive Grand Gulf capacity. Petitioners' simultaneous claims that FERC's allocation must be rejected as unduly discriminatory because it mismatches nuclear costs and capacity and that an alternate allocation that also fails to match nuclear costs and capacity is just and reasonable reveals the real reason for their support of Judge Head's solution. It is not that it resolves the flaws they see in the FERC allocation, but simply that it allocates them less Grand Gulf responsibility. Under these circumstances, the objection that the Commission mismatched costs and benefits rings rather hollow.

The City of New Orleans advances an additional reason why the Commission's allocation should be considered unduly discriminatory: AP&L's average cost for the nuclear *energy* produced by its capacity is 5.7 cents per kWh while the average cost of the nuclear energy produced by the other companies' nuclear capacity is 15 cents per kWh. *See* New Orleans Pet. Br. at 35. The objection is apparently that the Commission failed to equalize the companies' nuclear *production* costs and that this failure results in unduly discriminatory rates. Again, it is curious that this objection comes from a party that advocates adoption of Judge Head's solution since that solution seeks only to equalize Grand Gulf *capacity* costs,

not nuclear production costs. Nevertheless, the objection does not undermine FERC's allocation.

The Commission's decision sought only to remedy the drastic disparities in the costs of building the System's nuclear capacity by roughly equalizing the investment cost of that capacity among the companies. That step was considered sufficient to restore rough equality among the companies' overall capacity costs. Petitioner's objection is that the Commission failed to equalize nuclear *production* costs—*i.e.*, the costs of producing nuclear energy. There is no reason for the Commission to have focused on nuclear production costs rather than overall production costs. As previously discussed, only Grand Gulf energy is allocated with capacity. All other energy—whatever its source—is allocated pursuant to the 1982 System Agreement, with each company entitled to first call on its own lowest cost energy. Historically, and under the 1982 System Agreement, production costs have never been precisely equalized. These costs varied from company to company depending on each company's fuel mix at any given time. ALJ Head reviewed the companies' relative projected average annual production costs over a nine-year period under several alternative allocations. *See* 30 F.E.R.C. (CCH) at 65,156-57. For example, the nine-year average of production costs under the 1982 System Agreement as filed would be as follows:

AP&L — 7.47 cents/kWh
LP&L — 8.59 cents/kWh
MP&L — 11.00 cents/kWh
NOPSI — 11.65 cents/kWh

See id. at 65,157. The nine-year average under one of the production cost equalization proposals would be as follows:

AP&L — 8.82 cents/kWh
LP&L — 7.61 cents/kWh
MP&L — 9.46 cents/kWh
NOPSI — 8.96 cents/kWh

See id. Despite the production cost disparities under the 1982 System Agreement, Judge Head found no undue discrimination: "none of the differences brought out on the record are so compelling that they require the adoption of one form of production cost allocation." *Id.* at 65,169. Accordingly, he approved the 1982 System Agreement as filed.

Like ALJ Liebman, however, Judge Head found undue discrimination in the System's allocation of *capacity* costs. Unlike Judge Liebman, however, Judge Head believed this discrimination could be remanded by equalizing the investment costs of Grand Gulf alone rather than all nuclear capacity on the System. *See id.* at 65,172. Moreover, Judge Head pointed out that allocating AP&L a share of Grand Gulf capacity and energy would also serve to reduce the *production* cost disparities identified under the 1982 System Agreement. *See id.* at 65,169.

In view of Judge Head's above findings, affirmed and adopted by the Commission, *see* 31 F.E.R.C. (CCH) at 65,656, petitioner City of New Orleans' suggestion that production cost disparities among the companies require reversal of FERC's decision must be rejected. We affirm the finding by Judge Head and the Commission that production cost disparities under the 1982 System Agreement do not amount to undue discrimination. In deciding what discrimination is "undue," the Commission necessarily possesses discretion and exercises judgment in light of the facts established by the record. In this case, Judge Head identified "a strong factual reason for not restructuring the system to meet the current [production] cost disparity problems": "production cost equalization would be inconsistent with the history of intercompany transaction on the Middle South system." 30 F.E.R.C. (CCH) at 65,170. Like Judge Head's solution, the Commission's decision alters the UPSA by allocating AP&L a share of Grand Gulf responsibility. Indeed, since the Commis-

sion's decision allocates AP&L more Grand Gulf responsibility (36%), the former does even more than the latter to reduce the production cost disparities among AP&L and the other companies.

3. *Participation Unit Concept*

The remaining Mississippi petitioners—the Mississippi Public Service Commission, the Mississippi Attorney General, and the Mississippi Legal Services Coalition—raise many of the arguments relied on by the petitioners who support Judge Head's solution. These petitioners, however, urge a return to the participation unit method of allocating the System's excess capacity.

Like the other Mississippi parties, these petitioners argue that the Commission's decision mismatches nuclear investment costs and benefits and irrationally increases MP&L's Grand Gulf responsibility from 31.63% to 33%. We have already considered and rejected these arguments, *see supra* pp. 76-80, and these petitioners' contentions require only minimal additional discussion.

In objecting to the Commission's decision to increase MP&L's Grand Gulf responsibility, petitioners take issue with the Commission's observation that the result of its decision "is that all three major geographical areas served by the MSU System will share similar Grand Gulf cost burdens: AP&L—36%; MP&L—33%; and LP&L/NOPSI—33%." 32 F.E.R.C. (CCH) at 61,960. They claim that this "response" is "grossly inadequate" to explain why the Commission's allocation to MP&L is just and reasonable while the UPSA's slightly smaller allocation is not. *See* Brief of Petitioners, The Mississippi Public Service Commission, Edwin Lloyd Pittman, Attorney General for the State of Mississippi, and Mississippi Legal Services Coalition ("Mississippi Pet. Br.") at 56. Rather than focusing on geographical areas, they assert, "one must look at the actual size of each company in

order to assess the impact of the Grand Gulf allocation or cost burden on that company's individual ratepayers." Mississippi Pet. Br. at 60. This argument misunderstands the significance of the Commission's observation. Contrary to petitioners' suggestion, the Commission has not stated that any allocation that spreads costs proportionately over geographic regions is just and reasonable. By allocating nuclear investment costs according to relative demand, the Commission expressly recognized that Arkansas, Mississippi and Louisiana do not have equal loads. The Commission's point is simply that its allocation, unlike the UPSA's, requires Arkansas to bear a proportionate share of nuclear investment costs. It was the *relative* impact of the UPSA that FERC found unduly discriminatory. By requiring AP&L to share in the costs of Grand Gulf, the Commission could reasonably adopt an allocation that also slightly increased MP&L's responsibility.

We also have little difficulty rejecting petitioners' submission that "the participation unit concept utilized under the 1973 System Agreement is a concept for equalizing excess capacity which is . . . just, reasonable, and not unduly discriminatory." Mississippi Pet. Br. at 73. Under this proposal, the System would return to the 1973 System Agreement with MSE, the MSU subsidiary that owns Grand Gulf, as a party. Since MSE is not an operating company and has no demand, it will always be "long" on capacity, making Grand Gulf a participation unit. This means that the responsibility for Grand Gulf would be borne entirely by the "short" companies, shifting somewhat over time as the operating companies became more or less long or short.

Both Judge Liebman and Judge Head concluded that this proposal would be unduly discriminatory. *See* 30 F.E.R.C. (CCH) at 65,167; 26 F.E.R.C. (CCH) at 65,112. The Commission adopted and affirmed the findings of both judges on this point. *See* 31 F.E.R.C. (CCH)

at 61,655-56. These findings are conclusively established by the record. Petitioners acknowledge that MP&L is currently a "long" company and expected to remain so for approximately ten years. This means that LP&L and NOPSI, the "short" companies, would bear almost all of the responsibility for Grand Gulf during this period. That the proposal would result in profound discrimination is most readily seen by observing its impact on LP&L. As discussed, Grand Gulf and Waterford III are unique on the System in that it is the dramatic cost escalations of these units that disrupted the System's rough equalization of capacity costs among the operating companies. *See* 31 F.E.R.C. (CCH) at 61,654; *supra* pp. 69-71. Already saddled with 100% of the costs of Waterford III, LP&L would be required under petitioners' proposal to pay 90 to 100% of the costs of Grand Gulf over the next ten years. *See* 26 F.E.R.C. (CCH) at 65,112. As Judge Head recognized, the astronomical costs of Grand Gulf and Waterford III mean that these two units alone "will account for over 70% of the total system investment in production plant." 30 F.E.R.C. (CCH) at 65,145. Requiring one company to bear virtually all of the costs of both units exaggerates rather than alleviates the undue discrimination found under the UPSA and 1982 System Agreement. The Commission properly rejected this proposal.

4. *Production Cost Equalization*

The Louisiana petitioners—the Louisiana Public Service Commission, the State of Louisiana, Occidental Chemical Corporation, Georgia Gulf Corporation, and Jefferson Parish, Louisiana—support the Commission's finding of undue discrimination, but argue that some form of production cost equalization would be a more equitable and efficient remedy than the one ordered by the Commission. Petitioners' main contention is that the Commission failed adequately to explain its decision not to order full production cost equalization. We find this contention with-

out merit and hold that the Commission acted within its discretion in ordering a less intrusive means of remedying the undue discrimination found on the System.

Petitioners argue at length that, like the Commission's remedy, "production cost equalization is also fully supported by the Commission's conclusions of law and findings of fact, and that [the] latter alternative would more directly and more expeditiously achieve the objectives identified by the Commission as the basis for adopting nuclear investment equalization." Initial Brief of Petitioners Occidental Chemical Corporation, Georgia Gulf Corporation, and Jefferson Parish, Louisiana ("Louisiana Parties' Pet. Br.") at 33; *see* Brief of the Louisiana Public Service Commission and the State of Louisiana, Petitioner and Intervenor ("Louisiana Pet. Br.") at 44-47. Petitioners are surely correct in their assertion that production cost equalization would "virtually eliminate[] the possibility of serious future imbalances in generation cost responsibility among the operating companies." Louisiana Parties' Pet. Br. at 36. That, of course, is the nature of the remedy. But we have also concluded that the Commission's chosen remedy is sufficient to remedy the *undue* discrimination on the System; that is, the Commission could properly conclude that the remaining cost disparities do not constitute unlawful discrimination. *See supra* pp. 79-83. The Louisiana parties do not seriously dispute this conclusion. *See* Louisiana Pet. Br. at 39. Rather, their argument is that production cost equalization would remedy System cost disparities even more effectively than nuclear investment cost equalization and that the Commission did not adequately justify its decision to reject the former and adopt the latter. *See* Louisiana Parties' Pet. Br. at 42, 49.

In deciding whether to order production cost equalization or nuclear investment equalization, the Commission confronted a major policy choice. Though both alternatives would remedy undue discrimination, the former

would represent a dramatic disruption of the System's historical operations and of the states' settled interests and expectations. Accordingly, FERC chose the latter alternative. We hold that the Commission's decision was both rational and within its discretion.

Under the Louisiana Public Service Commission's production cost equalization proposal, the investment costs of all System capacity would be combined and allocated among the operating companies according to each company's capability responsibility—that proportion of System capacity equal to each company's proportion of System demand. *See* 30 F.E.R.C. (CCH) at 65,141. In addition, a rate would be established to equalize cost per kWh of all energy produced by that capacity. *Id.* After reviewing the historical operation of the System, Judge Head concluded that "production cost pooling and equalization constitutes a drastic deviation from past practices on the system relating to intercompany transactions and would change the underlying nature of such transactions." *Id.* at 65,168.

> Never during the modern history of the system (1949 on) has there been any arrangement governing intercompany transactions where all the costs of the production plants of the operating companies have been combined and then allocated to the respective operating companies based on some capability responsibility formula.

Id. at 65,167. Rather, the operating companies have always been responsible for the costs associated with the plants they build and finance, costs that necessarily vary somewhat from company to company. In addition, the companies have always had first call on their own lowest cost energy in meeting their demand. The System agreements have sought simply to equalize the System's *excess* energy and capacity among the companies. The *result* has been *rough* equalization of capacity and production costs.

Having found that "it is the large cost escalations of Grand Gulf and Waterford that have disrupted this pattern [of rough equalization]," 31 F.E.R.C. (CCH) at 61,654, the Commission properly decided to take only those steps that were necessary to compensate for this disruption. Those steps were to approve the 1982 System Agreement as filed and order nuclear capacity cost equalization. Production cost equalization would go much further and eliminate virtually all production and capacity cost disparities among the companies. Though we do not say that the Commission could not have ordered production cost equalization on this record, we think that the Commission correctly concluded that it was not necessary to remedy the undue discrimination found on the System. Recognizing that "[f]ull production cost equalization would be a substantial change from the allocation methodologies historically used on the MSU System," 32 F.E.R.C. (CCH) at 61,961, the Commission explained that "the adopted allocation is an attempt to equalize the imbalance of cost on the System with the least disruption possible to the historical operation of the System." *Id.*

Judge Head identified an additional "compelling" policy consideration against production cost equalization: "Federal regulation is meant to be supplemental to, not to supplant, State regulation." 30 F.E.R.C. (CCH) at 65,170. Observing that "the practical effect of ordering production cost equalization would be to bind the local State commissions in many of their rate base determinations," *id.*, Judge Head concluded that the reasons favoring equalization "are not so compelling that they justify the extensive intrusion into an area normally subject to regulation by the State commissions." *Id.* The Commission affirmed this conclusion, *see* 31 F.E.R.C. (CCH) at 61,656, and stated that its decision seeks "to alter in as limited a means as possible the agreed-upon cost scheme, in order to achieve just, reasonable, non-discriminatory and non-preferential rates." 32 F.E.R.C. (CCH) at 61,961. Having determined that production cost equalization was not

necessary to achieve lawful rates, the Commission properly considered the historical operation of the System as well as the regulatory interests of the states in exercising its discretion not to order such equalization. *Cf. Nantahala Power & Light Co.* v. *FERC*, 727 F.2d at 1348 ("A decision to order roll-in is essentially a matter of Commission discretion . . . .").

* * * *

We have now considered petitioners' numerous arguments against the Commission's decision and in favor of various alternate allocations. We find these arguments unpersuasive and hold that the Commission acted within its authority to remedy undue discrimination and that its decision was rational. We also have considered all other arguments suggesting that the Commission acted improperly and find them to be without merit.

D.

In this section, we consider two remaining claims: that Commissioner Richard improperly failed to recuse himself and that the Commission abused its discretion in failing to reopen and update the record.

1. *Recusal*

Several of the Mississippi parties assert that "[t]he failure of Commissioner Oliver G. Richard, III to recuse himself in this case was error." Mississippi Pet. Br. at 71. Their claim is that Commissioner Richard's past association with Senator J. Bennett Johnston of Louisiana —an intervenor below as a member of the full Louisiana congressional delegation—"created the appearance of bias and impropriety sufficient to compel the Commissioner's recusal." Mississippi Pet. Br. at 72. Like Commissioner Richard and the Commission, we find petitioners' claim to be without merit.

Recusal is required only when the actions of a decisionmaker lead one to conclude that he has prejudged the case.

See Cinderella Career & Finishing Schools, Inc. v. *FTC*, 425 F.2d 583, 591 (D.C. Cir. 1970). Petitioners themselves acknowledge that recusal decisions are subject to a very deferential, abuse of discretion standard of review. *See* Mississippi Pet. Br. at 72 (*citing Davis* v. *Board of School Comm'rs of Mobile County*, 517 F.2d 1044 (5th Cir. 1975)). Under this standard, it is clear that Commissioner Richard acted properly.

Commissioner Richard worked for Senator Johnston from 1977 to 1981 as a legislative assistant dealing with energy issues. This fact alone does not suggest bias. As Commissioner Richard observed, "my employment with the Senator ended . . . almost one year before the *Middle South* proceedings began. I had no prior contact with the facts or legal issues involved in *Middle South* before joining the Commission in 1982." 31 F.E.R.C. (CCH) at 61,671. Petitioners do not dispute these facts. Rather, they claim that Commissioner Richard abused his discretion by "neglect[ing] to follow FERC's own Administrative Rules." Mississippi Pet. Br. at 72 (*citing* 18 C.F.R. § 385.504(c)(1), (2)). We disagree.

First, these rules do not apply to the Commissioners; they are directed only to presiding officers at hearings ordered by the Commission. Second, even if applicable, the rules would not support petitioners' claims. They provide simply that a presiding officer who believes himself to be "disqualified" may withdraw from a hearing, *see* 18 C.F.R. § 385.504(c)(1), and that the Commission may order recusal "upon good cause," *see id.* § 385.504 (c)(2).

2. *Reopening the Record*

The Louisiana petitioners assert that the Commission arbitrarily and capriciously refused to reopen the record to update the cost estimates of Grand Gulf and Waterford III. We find petitioners' arguments unavailing and

hold that the Commission acted within its discretion in deciding not to reopen the record.

In *ICC* v. *Jersey City*, 322 U.S. 503 (1944), the Supreme Court established the general rule that federal courts should be extremely reluctant to require an agency to reopen a record on the ground that the evidence has become stale. *Id.* at 514. Indeed, the question is often "entrusted to agency discretion." *See Delta Air Lines* v. *CAB*, 561 F.2d 293, 307 (D.C. Cir. 1977), *cert. denied*, 434 U.S. 1045 (1978); *accord Bowman Transp.* v. *Arkansas-Best Freight Sys.*, 419 U.S. 281 (1974). As a general rule, this court has found that a remand may be necessary "where there has been a change in circumstances . . . that is not merely 'material' but rises to the level of a change in 'core' circumstances, the kind of change that goes to the very heart of the case." *Greater Boston Television Corp.* v. *FCC*, 463 F.2d 268, 283 (D.C. Cir. 1971), *cert. denied*, 406 U.S. 950 (1972). We cannot conclude that the circumstances cited by petitioners evidence a change which goes "to the heart of the case" or that they represent a change in the "core circumstances."

In this case, the Commission adopted Judge Liebman's remedy, which relied on the cost data in the record developed before him. In rejecting the Louisiana parties' request to reopen the record, the Commission stated: "Because cost estimates for these units have been continually changing and because the costs as well as demand projections in ER82-616 were reasonable when made and were subject to cross-examination, we find it appropriate to adopt Judge Liebman's recommendation without modification at this time." 31 F.E.R.C. (CCH) at 61,657. The Commission took the same position on rehearing, stating that "it is necessary to use some fixed point in time in order to provide finality to a proceeding, rather than continuously updating or using spot adjustments." 32 F.E.R.C. (CCH) at 61,961.

Petitioners argue that the Commission should have reopened the record on rehearing because by that time final cost figures were available for both Grand Gulf and Waterford III. Use of these costs, they argue, would have better served the interests of finality. But, updating the record would not have been as effortless as petitioners suggest. First, the intervening increase in costs cited by petitioners has never been subject to cross-examination, and AP&L, at least, suggests that the amount is subject to dispute. *See* Brief of Arkansas Power & Light Company as Intervenor at 28 n.23. Moreover, AP&L claims that the intervening improvements it has made to ANO I and II by order of the NRC would also have to be considered in any recalculation based on updated costs. Second, the Commission could not merely update cost figures; demand projections would have to be revised as well since both are necessary to properly equalize nuclear capacity costs. Thus, we cannot agree with petitioners that finality could have been better served by reopening the record. The potential delay involved might have been seriously detrimental since Grand Gulf was about to become operational and the matter had to be resolved.

Petitioners make much of the fact that the Commission considered extra-record evidence to increase the rate of return on equity it allowed MSU. "Given its willingness to consider post-record evidence in adjusting the rate of return, to benefit the utility, the FERC should have taken similar action to avoid discrimination among consumers." Louisiana Pet. Br. at 44. Petitioners' claim is unpersuasive. Setting rates of return is a completely different undertaking from allocating costs. *See Illinois Power Co.*, 15 F.E.R.C. (CCH) ¶ 61,650 (1981). In the case of the former, the Commission frequently adjusts the return upward when warranted by changing circumstances in the financial markets after the close of the record since such information is not typically subject to dis-

pute. As discussed, cost allocation involves information of a quite different character. Thus, we must conclude that petitioners have fallen "far short of demonstrating 'the most extraordinary circumstances' necessary to justify compelling the agency to reopen the record." *Nantahala Power & Light Co.* v. *FERC*, 727 F.2d at 1352 (*quoting Bowman*, 419 U.S. at 296).

For all of the foregoing reasons, the Commission's decision is

Affirmed.

BORK, *Circuit Judge, concurring in part and dissenting in part*: I concur in the majority's reasoned analysis of the jurisdictional challenges raised in this case. I dissent from the majority's affirmance of the merits of the Commission's decision because I believe that the Commission has failed adequately to explain two critical issues. I would reverse and remand for further consideration of these issues.

First, the Commission has not explained adequately its criteria for determining what is "undue discrimination" or why the course it has chosen is not also unduly discriminatory. The Commission found the UPSA as filed to be unduly discriminatory because the cost of nuclear capacity varied widely from company to company. Specifically, the Commission found the companies' costs of nuclear capacity were approximately as follows:

AP&L	$ 531,000 per megawatt
LP&L	2,211,000 per megawatt
MP&L	2,247,000 per megawatt
NOPSI	2,090,000 per megawatt

See 26 F.E.R.C. (CCH) at 65,107. Under the Commission's remedy, however, nuclear capacity costs remain vastly disparate:

AP&L	$ 858,000 per megawatt
LP&L	2,219,000 per megawatt
MP&L	2,156,000 per megawatt
NOPSI	2,094,000 per megawatt

See id. at 65,109. Those are still very large differences. Indeed, the disparities have changed hardly at all. In response to the argument that this result was also unduly discriminatory, the Commission stated:

> What our decision purports to do is to eliminate drastic rate disparities at the wholesale rate level which are associated with units used for the mutual benefit of all companies, and to do so in a manner which disturbs the historical operation of the System

> as little as possible, and which allows the individual companies to retain as fully as possible the benefits of units they have financed and constructed. In other words, we have sought to achieve an equitable balance between the interests of the individual companies and the System as a whole, consistent with the System Agreement.

32 F.E.R.C. (CCH) at 61,959.

This explanation is inadequate for three reasons. First, the Commission does not explain why the remaining very great disparities should not be considered "drastic" and hence to constitute "undue discrimination." No criteria whatever are offered for determining when such discrimination exists. Second, the argument that the Commission did not want to disturb the historical operation of the System does not support its finding because historically costs were equalized under the System. Finally, the Commission's statement that it has attempted to allow "individual companies to retain as fully as possible the benefits of the units they have financed and constructed" is unacceptable as a rationale. As discussed at length in the majority opinion, a basic, and necessary, premise of the Commission's jurisdiction in this case, as well as the validity of the decision, is that the companies are not autonomous and that decisions are made for the System as a whole. *See* maj. op. at 33-39, 66-68.

Second, I believe that the Commission's explanation for its decision to include the capacity costs of all nuclear plants, rather than considering only the costs of Waterford III and Grand Gulf, or the costs of all coal and nuclear plants, is not rational. The Commission considered the capacity costs of all nuclear plants because the unforeseen problems that led to dramatic costs overruns were "unique to constructing nuclear units." 31 F.E.R.C. (CCH) at 61,655. But the cost overruns were not unique to all nuclear plants; they were unique only to Grand Gulf and Waterford III. The investment costs of the

ANO units were comparable to the investment costs of the coal units. *See* 32 F.E.R.C. (CCH) at 61,960. Thus, if the Commission was attempting only to address the "unique" cost overruns, which it has stated as its rationale, then it would seem reasonable to consider only the costs of Grand Gulf and Waterford III. If, however, the Commission wished to include the costs of the ANO units, for some unexplained reason, then, it would appear, the Commission reasonably should have included the costs of the coal units as well.

APPENDIX B

CITED AS "32 FERC ¶. . . ."

[¶61,425]

Middle South Energy, Inc. Docket Nos. ER82-616-000, ER82-616-005 through ER82-616-015, ER82-616-017 through ER82-616-024, and ER82-616-028;

Middle South Services, Inc., Docket Nos. ER-82-483-000, ER82-483-003 through ER82-483-021, and ER82-483-024

Opinion No. 234-A; Order Denying Rehearing and Granting Interventions

(Issued September 26, 1985)

Before Commissioners: Raymond J. O'Connor, Chairman; A. G. Sousa and Charles G. Stalon.

[Note: Initial Decision of the administrative law judge, issued February 3, 1984, appears at 26 FERC ¶63,044.]

[Opinion No. 234-A Text]

On June 13, 1985, the Commission issued Opinion No. 234, 31 FERC ¶61,305, involving the appropriate allocation of capacity costs incurred on the Middle South Utilities (MSU) System, including the cost of the Grand Gulf 1 nuclear unit, among the four wholly owned subsidiary operating companies of MSU. The four operating companies are Louisiana Power & Light company (LP&L), Mississippi Power & Light Company (MP&L), Arkansas Power & Light company (AP&L), and New Orleans Public Service, Inc. (NOPSI). Opinion No. 234 determined that all MSU System production costs should not be equalized among the operating companies, but that nuclear capacity investment costs should be equalized. To achieve this, the Opinion adopted the following Grand Gulf 1 allocation percentages which had been recommended by Judge Liebman in an initial decision issued in Docket No. ER82-616, 26

FERC ¶63,044 (1984): AP&L: 36%, LP&L: 14%, MP&L: 33%, NOPSI: 17%, Total: 100%.

Requests for rehearing of Opinion No. 234 were filed on July 3, 11, 12, and 15, 1985, by the following parties: Arkansas Industries; Mississippi Legal Services Coalition; Occidental Chemical Corporation and Georgia Gulf Corporation; the Attorney General of the State of Mississippi; the Louisiana Public Service Commission (LPSC); the Cities of Conway and West Memphis, Arkansas; the Arkansas Public Service Commission and Missouri Public Service Commission (APSC/MoPSC); MP&L; the Arkansas and Missouri Congressional Delegations; AP&L; Mississippi Representative Webb Franklin; AMAX, Inc.; the Cities of Benton, North Little Rock, Osceola, and Prescott, Arkansas, and the Farmers Electric Cooperative Corporation; Jefferson Parish, Louisiana; the State of Arkansas (which joins in and adopts the rehearing request of the APSC/MoPSC); Middle South Energy, Inc. (MSE); LP&L and NOPSI; the Mississippi Public Service Commission (MPSC); the City of New Orleans; and Mississippi Industries. Eight of these parties also filed requests for a stay of Opinion No. 234, either pending rehearing or pending appellate review.

On August 2, 1985, the Commission issued an order granting rehearing for purposes of further consideration and denying a stay. 32 FERC ¶61,207. The portion of the order denying a stay was clarified and rehearing of the stay denial was denied by order issued September 3, 1985, 32 FERC ¶61,346. This order addresses the issues raised in the requests for rehearing of Opinion No. 234.

The arguments raised on rehearing concern the Commission's authority to reallocate Grand Gulf capacity costs, the line between State/Federal jurisdiction in this area, our findings concerning the integrated nature of the MSU System and decisionmaking on the System, and the appropriateness of the precise allocation plan we adopted.

For the most part, the arguments raised on rehearing are ones that were already made and considered on exceptions. We have reviewed the arguments and conclude that rehearing should be denied. However, there appear to be certain areas of the Opinion which we need to clarify or expand upon, and certain mis-statements or erroneous interpretations of the Opinion made on rehearing which should be addressed. These are discussed below.

Commission Jurisdiction

On rehearing, numerous parties[1] again raise several arguments concerning the Commission's authority to amend the UPSA and the 1982 System Agreement. The major arguments, also raised previously below, are: (1) Grand Gulf is a generating facility and thus is not subject to our jurisdiction under Section 201(b) of the Federal Power Act (FPA); (2) MSE is not a "public utility" under Section 201(e) of the FPA, and thus is not subject to our jurisdiction; (3) the Commission has no jurisdiction to force a purchase or sale of Grand gulf, and thus cannot alter the contractually agreed upon allocations; and (4) the *Mobile-Sierra* doctrine[2] precludes modification of the voluntary UPSA and 1982 System Agreement.

We rejected the above arguments in Opinion No. 234 primarily by summarily adopting the discussions of Judges Liebman and Head, 26 FERC at pp. 65,113-18 and 30 FERC at pp. 65,146-47, 65,148-51,[3] and 65,154. Some parties, for example the APSC/MoPSC, argue or imply on rehearing that the Commission failed to articulate its rea-

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[1] AI; the APSC/MoPSC; the Cities of Conway, *et al;* the Arkansas and Missouri Congressional Delegations; the Cities of Benton, *et al.*, AP&L; AMAX, Inc.; and the MPSC.

[2] *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) (*Mobile*); and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) (*Sierra*).

[3] We wish to correct a typographical error at p. 61,643 of the Opinion which referred to pp. 65,140-51. This should be pp. 65,148-51.

sons for rejecting arguments that it lacks jurisdiction to order AP&L to purchase a portion of Grand Gulf capacity. We have again reviewed all of the jurisdiction arguments of the parties, as well as the portions of the judges' decisions which we affirmed. Although the initial decisions each focus on our authority to amend separate contracts, we believe that, taken together, they sufficiently address the majority of the challenges made to our jurisdiction in the two dockets, and we continue to agree with their general reasoning and conclusions. In view of certain matters raised on rehearing, however, we wish to expand briefly on the judges' discussions and to clarify our position concerning certain alleged inconsistencies between the judge's decisions. First, we think it appropriate to review the judges' discussions, cited above, concerning jurisdiction.

In response to the Arkansas parties' arguments that the Commission lacks jurisdiction to allocate any Grand Gulf cost responsibility to AP&L, Judge Liebman initially found that AP&L had been extensively involved in every aspect of the decision to build, finance, and allocate the unit. He further found that Section 206(a) of the FPA clearly gives the Commission authority to supervise contracts among utilities and also mandates that the Commission revise the terms of such contracts to eliminate undue preferences or discrimination.[4] He concluded that the argument that there is no jurisdiction to adjust the UPSA percentages could not be reconciled with the Commission's duty under Section 206(a), and would also render meaningless the inde-

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[4] Judge Liebman specifically noted that Section 206(a) of the FPA provides in pertinent part that if the Commission finds that any "*contract affecting*" any jurisdictional "rate, charges, or classification, demanded, observed, charged, or collected by any public utility" is "unjust, unreasonable, unduly discriminatory or preferential," the Commission is directed to "determine the just and reasonable . . . *contract to be thereafter observed and in force*, and shall fix the same by order." (Emphasis added.) 26 FERC at pp. 65,113-14.

pendent prohibition against undue discrimination embodied in Section 205(b) of the Act.

Judge Liebman next rejected the Arkansas parties' reliance on the *Mobile-Sierra* doctrine, *supra,* nothing that in the *Mobile* Opinion, the Court was careful to emphasize that its holding in no way impaired the regulatory powers of the Commission, since the rate contracts in question remained "fully subject to the paramount power of the Commission to modify them when necessary in the public interest." 350 U.S. at 344. He also noted the Court's recognition in *Sierra* of the Commission's undoubted power under Section 206(a) to prescribe a change in contract rates whenever it determines such rates to be unlawful. He concluded that it was clear from the record that the failure to allocate any portion of Grand Gulf power and costs to AP&L confers an undue preference on AP&L without factual justification and unduly discriminates against the other operating companies. This failure, he stated, fits within the "unduly discriminatory" component of the *Sierra* test and thus "adversely affects the public interest."[5] Judge Liebman further found that the *Mobile-Sierra* doctrine does not abrogate but rather reinforces the FERC's power under Section 205(b).

Next, Judge Liebman distinguished *Municipalities of Groton v. F.E.R.C.,* 587 F.2d 1296 (D.C. Cir. 1978), and *Central Iowa Power Cooperative v. F.E.R.C.,* 606 F.2d 1156 (D.C. Cir. 1979), which had been relied upon for the proposition that voluntary contracts could not be revised. He

[5] The "unduly discriminatory" component of the *Sierra* test to which Judge Liebman referred is the Court's holding that the purpose of the power given the Commission by §206(1) is the protection of the public interest, as distinguished from the private interest of utilities, and that: "[T]he sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest—as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory." 350 U.S. at 355.

further rejected the argument that *Southern Company Services, Inc.*, 20 FERC ¶61,332 (1982) and *Georgia Power Co.*, Opinion No. 711, 52 FPC 1343 (1974), precluded the Commission from ordering new entitlements.

Judge Liebman thus denied assertions that the Commission has no authority to modify the UPSA or compel AP&L to purchase Grand Gulf capacity, although he did not directly discuss Section 201 of the FPA.

Judge Head followed the general reasoning of Judge Liebman. His discussion of jurisdiction issues began with a rejection of the Arkansas parties' *Mobile-Sierra* arguments, particularly the contention that the doctrine allows abrogation of voluntary contracts only in cases of "unequivocal public necessity." He distinguished the *Mobile-Sierra* line of cases and, as did Judge Liebman, noted the *Mobile* Court's finding that contracts remain fully subject to the Commission's power to modify them in the public interest, as well as the *Sierra* holding that the Commission has power under Section 206(a) to prescribe a change in contract rates where such rates are determined to be unlawful. He further found that the *Mobile-Sierra* doctrine makes it clear that the Commission has power, pursuant to Sections 205 and 206 of the FPA, to revise the System Agreement on the basis that it is unjust, unreasonable, unduly discriminatory or preferential.

In reference to arguments that Sections 201(a) and (b) of the FPA prohibit cost equalization because it would extend Federal jurisdiction over generating plants and would intrude into state jurisdiction, Judge Head concluded that while the statutory language indicates that the Commission has jurisdiction only over matters not subject to state regulation, and does not have jurisdiction over generating facilities, nevertheless it specifically gives the Commission authority over the sale of electric energy at wholesale and, as a result, there is no doubt that the Commission has jurisdiction over the 1982 System Agree-

ment. He further concluded that since the 1982 System Agreement constitutes a rate change filed under Section 205, the jurisdiction of the Commission under Section 206(a) to revise the agreement and set different rates cannot reasonably be challenged.

Next, Judge Head cited the Supreme Court's recent decision in *Arkansas Electric Corp. v. Arkansas Public Service Comm'n*, 461 U.S. 375 (1983), which he interpreted as broadening the area of state regulation but also as recognizing the need to reconcile and accommodate the competing demands of state and national interests. Judge Head stated that the Middle South case required such reconciliation and that while state commissions clearly have control over the generating plants they have approved for construction, nonetheless this Commission has authority under Sections 205 and 206 to assure that inter-company transactions are just, reasonable, nondiscriminatory and non-preferential. He concluded that the language in Section 201(a), restricting the FERC's authority to matters not subject to state regulation, does not nullify the Commission's clear authority to regulate the 1982 System Agreement, even if the exercise of FERC jurisdiction might appear inconsistent with the broadly expressed statement in Section 201(a).The fact that state commissions also have regulatory power in an affected area, rate base, does not preclude exercise of the Commission's authority, he concluded.

In light of the above findings, Judge Head held that production cost equalization was within the jurisdiction of the Commission if there were sufficient public interest reasons to revise the 1982 System Agreement in that fashion, but that the statutory scheme of the FPA and the deference that should be paid to state ratemaking authority were factors to be considered as weighing against production cost equalization.

Judge Head thus followed Judge Liebman's general reasoning concerning Commission authority under Sections 205 and 206 to amend contracts. His focus, however, was on the System Agreement rather than on the UPSA or MSE.

Later in his discussion, Judge Head focused briefly on the specific question of whether equalization constitutes a forced purchase of capacity. He stated that while it is correct that the FERC cannot compel one utility to purchase from or sell to another (citing *Southern Company Services, Inc.*, 20 FERC ¶61,332 (1982)), this situation is not present in the instant case. He concluded that this proceeding is not dealing with a forced purchase, but rather with the proper method of allocating costs under the 1982 System Agreement.

As previously indicated, we interpret the above findings of the two judges to be generally consistent. However, because the judges were each focusing on different contractual agreements, we shall review the pertinent provisions of the FPA and clarify our position on any perceived inconsistencies between the two decisions.

Sections 201(a) and (b) of the FPA set forth the Commission's jurisdiction:

> Section 201.(a) It is hereby declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this Part and the Part next following and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

> (b)(1) The provisions of this Part shall apply to the transmission of electric energy in interstate commerce and *to the sale of electric energy at wholesale in interstate commerce,* but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction, except as specifically provided in this Part and the Part next following, over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter. (emphasis supplied)

We agree with Judge Head that while the statutory language of Section 201 of the FPA grants the Commission jurisdiction only over matters not subject to state regulation, and explicitly removes from Commission jurisdiction facilities used for the generation of electric energy (except as specifically provided), it nevertheless explicitly grants jurisdiction over the sale of electric energy at wholesale in interstate commerce. It, therefore, is clear that we have jurisdiction under Section 201 over the 1982 System Agreement because the agreement involves sales of electric energy at wholesale in interstate commerce. Despite the statutory language that the Commission does not have jurisdiction over generating facilities, we further conclude that Section 201 does not preclude our jurisdiction over the UPSA. Our reasoning is discussed below.

In view of the language in the "but" clause of Section 201(b)(1) that the Commission "shall not" have jurisdiction over facilities used for the generation of electric energy,

it is clear that the FPA places a limitation on our authority over generation facilities. However, it is equally clear that Section 201(b)(1) of the Act grants us jurisdiction over the sale of electric energy at wholesale in interstate commerce. We cannot interpret the "but" clause of Section 201(b)(1) as nullifying the authority granted to us in the first sentence of Section 201(b)(1), in situations where generation facilities are used for interstate wholesale sales. To interpret the statute otherwise would be inconsistent with the declaration in Section 201(a) that Federal regulation of the sale of energy at wholesale in interstate commerce is necessary in the public interest. Furthermore, it would permit companies engaging in wholesale sales in interstate commerce to avoid the intended Federal regulation in Section 201(a) by forming a generation-only subsidiary to engage in the wholesale sales which otherwise would come under our jurisdiction. Thus, where the sales made from a generating facility are sales of electric energy at wholesale in interstate commerce, we conclude that under the FPA we retain jurisdiction over those sales.

Our interpretation of the FPA and assertion of jurisdiction over the UPSA are supported by *Hartford Electric Light Co. v. F.P.C.*, 131 F.2d 953 (2d Cir. 1942), *cert. denied*, 319 U.S. 741 (1943). In *Hartford*, the FPC had issued accounting orders directing the company to comply with the Commission's Uniform System of Accounts. Hartford asked the Court of Appeals to set aside the Commission order, arguing that it was not a "public utility" subject to jurisdiction under the Federal Power Act. Although Hartford sold power and energy to a neighboring public utility, Connecticut Power Company, which in turn sold some of the power and energy in interstate commerce, Connecticut Power Company owned all of the transmission facilities up to the wall bushings on the Hartford generating plant. Hartford argued that facilities were either transmission or generation facilities. Since it had no transmission facilities, it must only have generation facilities,

and these were not jurisdictional facilities pursuant to the Federal Power Act. The court, however, took a different view, and affirmed the Commission:

> Section 201(b) confers jurisdiction over not only facilities (1) for interstate *transmission* but also—and—*disjunctively*—over facilities (2) for interstate wholesale *sales*. If the Commission has no jurisdiction under §201(b) over generation facilities, then that part of that section conferring jurisdiction over facilities for interstate wholesale sales becomes meaningless—unless there is a third category of facilities, i.e., those used neither for transmission nor for generation. We must, therefore, look for that third category. We find it in petitioner's corporate organization, contracts, accounts, memoranda, papers and other records, in so far (*sic*) as they are utilized in connection with such sales. (Citation omitted). 131 F.2d at 961.

The court then found Hartford a "public utility" based on an alternative ground:

> Even if we assume that petitioner has no facilities for interstate transmission, and that petitioner's books, records, etc., are not facilities for wholesale sales in interstate commerce, so that petitioner has nothing except facilities for generation, still petitioner's contention is unsound. For *we consider that generation facilities, where used as aids to such sales, are within the Commission's jurisdiction under §201(b).* Id. (Emphasis added.)

The Supreme Court in *Connecticut Light and Power Company v. F.P.C.*, 324 U.S. 515 (1945), reversed a lower court's finding that Section 201(b) of the FPA allowed jurisdiction over facilities used for local distribution, and rejected some of the *Hartford* rationale that the lower court had relied upon. However, the Supreme Court also recognized the *Hartford* decision's alternate ground for

jurisdiction, specifically noting that the *Hartford* court had recognized the need for finding that the generating facilities in that case were *used as facilities for interstate wholesale sales of electric energy, and were therefore within the jurisdiction of Section 201(b) of the A* The lower court in the *Connecticut* case, it noted, had failed expressly to make such a determination. 324 U.S. at 528-29, note 6.

In the instant case, there is no question that the Grand Gulf 1 generation facilities are used as facilities for interstate wholesale sales, since sales made by MSE from those facilities involve sales of electric energy at wholesale in interstate commerce. We thus reject the argument that we have no jurisdiction over the UPSA sales because Grand Gulf is a generating facility not subject to our jurisdiction, or that we have no jurisdiction over MSE because it does not own facilities subject to our jurisdiction.[6]

We next address whether, assuming jurisdiction over the UPSA sales, we have authority to amend the agreement so as to "force" parties to purchase and sell capacity in amounts other than those contractually agreed upon. The APSC/MoPSC and AP&L contend that Judges Head and Liebman made inconsistent rulings in this regard. Judge Head, 30 FERC at p. 65,154, concluded that:

> . . . while it is correct that FERC cannot compel one utility to purchase from or sell to another, *Southern Company Services, Inc.*, 20 FERC ¶61,332 (1982), this situation is not present in the instant case. The MSU operating companies have not refused to share generating costs but rather the 1982 System Agreement covers how such exchanges should take place and at what rates. The Commission in this proceeding is not

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[6] *Cf. Middle South Energy, Inc. v. Arkansas Public Service Comm'n*, Nos. 84-2409, 84-2410, and 84-2480 (8th Cir. Aug. 23, 1985), *aff'g. Middle South Energy, Inc. v. Arkansas Public Service comm'n*, 593 F. Supp. 363 (D. Ark. 1984).

dealing with a forced purchase but with the proper method of allocating costs among the affiliated MSU companies, a matter well with in FERC's authority. *See Central Iowa Power cooperative v. F.E.R.C.*, 606 F.2d 1156 (D.C. Cir. 1979), and *Municipalities of Groton v. F.E.R.C.*, 587 F.2d 1296 (D.C. cir. 1978).

Judge Liebman, 26 FERC at pp. 65,115-16, also relying on *Central Iowa and Municipalities of Groton,* and after thoroughly discussing the two cases, rejected the argument that the Commission cannot reassign allocation percentages (and impliedly "compel" purchases). In fact, he found that the *Central Iowa* court had confirmed the Commission's authority to compel additional pool services if a voluntary pooling agreement were found unjust, unreasonable, unduly discriminatory or preferential, and that this finding furnishes direct support for the Commission to reallocate the Grand Gulf percentages in order to correct the discriminatory nature of the UPSA.

In Opinion No. 234, we determined, 31 FERC at p. 61,643, that the issue here is not whether a company should be forced to purchase or sell power, but rather is the appropriate allocation of costs among integrated companies owned by the same parent. On rehearing, LP&L and NOPSI argue that we should adhere to this finding but, as an alternative to the finding, conclude that Section 206(a) authorizes the Commission to establish new terms for a contract found to be unjust, unreasonable, unduly discriminatory or preferential, and that the section imposes no restrictions on new terms dealing with the amount of power purchased and sold.

Although Judge Head concluded that the Commission could not compel a utility to purchase from or sell to another, we do not interpret his decision as applying to cases such as this one, where we are dealing with contracts involving jurisdictional sales and where it is necessary to "compel" a different purchase in order to achieve just,

reasonable, and non-discriminatory rates. To interpret Judge Head's statement otherwise would be inconsistent with his prior conclusion, 30 FERC at p. 65,150, that the Commission's authority under Section 206(a) to order some form of production cost equalization cannot reasonably be challenged, and his statement, 30 FERC at p. 65,151, that the Commission has authority, in exercising its public interest duties under Sections 205 and 206 of the FPA, to assure that the inter-company transactions are just, reasonable, non-discriminatory and non-preferential.

The case cited by Judge Head in making his statement that the Commission cannot compel a purchase or sale, *Southern Company Services, Inc.*, was appropriately distinguished by Judge Liebman and was recognized by Judge Head as involving a factually different situation than the one here. *Southern* involved a unit power sales agreement between Florida Power & Light Company (FP&L) and Southern Company Services (Southern). Seminole objected to the agreement, alleging that if FP&L purchased from Southern rather than Seminole, it could drive Seminole's costs upward and make it more difficult for Seminole to compete with FP&L for retail customers. The Commission rejected Seminole's argument, noting that Seminole had failed to assert that the rates under the agreement were unjust or unreasonable, or that any part of the agreement was unduly discriminatory or preferential.

On rehearing, the Arkansas parties continue to cite *Southern* as standing for the proposition that the Commission has no authority to order a utility to buy from a particular source. As discussed above, the Commission rejected Seminole's arguments on narrower grounds, i.e., that Seminole's broad anticompetitive allegations did not properly assert a violation of the FPA. Additionally, there are two significant distinctions between *Southern* and the case before us. First, the agreement in Southern was not, as here, among commonly owned affiliates on an integrated system. Second, Seminole was not a party to the

agreement being contested, whereas here all of the parties, including AP&L, who have been re-allocated Grand Gulf shares, are signatories to the UPSA.

Based on the above, we do not view the decisions of Judges Head and Liebman to be inconsistent concerning our authority to amend the terms of the UPSA pursuant to Sections 205 and 206. We decline to grant the rather broad request of LP&L and NOPSI that we find that Section 206 "imposes no restriction on new terms dealing with the amount of power purchased or sold." (Rehearing request, p. 3.) However, we wish to clarify that under the circumstances presented by these dockets, we view Sections 205 and 206 as providing authority to change the allocation percentages as necessary to achieve just, reasonable, nondiscriminatory and non-preferential rates, whether or not the central issue is viewed as one of cost allocation or as "forced" purchases.

In reference to the above conclusion, we emphasize that the UPSA cannot be viewed in isolation. It is an agreement which "supplements or supersedes" the coordination arrangements among the MSU utilities,[7] and, as noted by Judge Liebman, is a contract "affecting" rates under the 1982 System Agreement. Given the particular circumstances of this case, we think it clear that we have authority to amend the UPSA and/or the System Agreement pursuant to Sections 205 and 206.

The *Mobile-Sierra* arguments raised on rehearing must again be rejected. The same arguments were adequately addressed and rejected by Judges Liebman and Head, whose discussions we affirmed in Opinion No. 234 and are summarized herein. However, there is one argument on rehearing which we will briefly address. The APSC/MoPSC claim (rehearing request, p. 103) that the rulings of the two judges are contradictory in that Judge Liebman im-

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[7] 31 FERC ¶61,304, at p. 61,627 (1985) (Order on remand).

plied that the *Mobile-Sierra* doctrine applies to the UPSA, but Judge Head, 30 FERC at p. 65,147, found the doctrine inapplicable because MSS was not attempting by filing the 1982 System Agreement to change a fixed rate contract.

We disagree with the APSC/MoPSC that the judges' *Mobile-Sierra* findings are contradictory. What Judge Head found at p. 65,147 of his decision was that "the specific ruling in *Sierra* proscribing unilateral contract changes by rate filings, is not applicable." He went on to find that the *Mobile-Sierra* doctrine makes clear that the Commission has the power under Sections 205 and 206 of the FPA to revise a contract that is unjust, unreasonable, unduly discriminatory or preferential, and that the doctrine "does highlight the authority of the commission to approve the 1982 System Agreement as filed, or to revise it if to do so is in the public interest." *Id.* Judge Liebman likewise recognized that the *Sierra* case focused on a situation where a public utility unilaterally was attempting to increase a fixed rate contract with a customer. 26 FERC at p. 65,114. He further found, however, as did Judge Head, that the *Mobile-Sierra* doctrine does not say that a voluntary contract can never be modified to rectify a statutory violation such as undue discrimination. *Id.* We fail to see how these interpretations or rulings are contradictory.

We have concluded in these dockets that the 1982 System Agreement and the UPSA, as filed, would result in rates that are not just, reasonable, and non-discriminatory, and we have determined new rates and amended contracts to remedy this. We, therefore, have complied with the statutory authority granted to us under Sections 205 and 206 of the FPA.

One last matter to be addressed concerning jurisdiction is a request by AI that the Commission clarify its discussion at p. 61,643 of Opinion No. 234 concerning Federal preemption and *Arkansas Electric Cooperative Corp. v. Ar-*

kansas Public Service Comm'n, 461 U.S. 375 (1983). AI states that our Opinion apparently equates the concepts of "jurisdiction" and "preemption" and contends that, "Surely, despite its broad assertion of federal preemption, the Commission is not suggesting that Congress meant for it to dominate the field of electric power regulation to the total exclusion of the states." (Rehearing request, p. 2.) AI asks the Commission to clarify its position or delete its reference to preemption.

AI totally misconstrues our opinion if it reads the Opinion as implying that the states have no jurisdiction in the field of electric power regulation. Several parties had cited the *Arkansas* case as supporting broader state jurisdiction over electric rates. The intent of the cited language in our opinion was to distinguish the case from the instant situation and to clarify that the case did not restrict this Commission's clear jurisdiction over sales of electric energy at wholesale in interstate commerce under Section 201(b) of the FPA. Judge Head appropriately considered the *Arkansas* case, 30 FERC at pp. 65, 150-51, and we concurred in his discussion of the need to balance Federal and state interests in exercising our jurisdiction. Furthermore, we think our opinion, taken as a while, as well as Judge Head's discussion, which we adopted, clearly recognize the role of the states in regulating retail electric rates and the need to balance overlapping state and Federal electric rate jurisdiction.

The other jurisdiction arguments made on rehearing are, in general, repetitive of ones already made and considered on exceptions and were adequately addressed in those portions of the initial decisions which we affirmed in Opinion No. 234, or in the opinion itself.

State/Federal Relationship

Related to the above arguments concerning the line between state and Federal jurisdiction over rates is the general argument that the Opinion destroys effective state

regulation of retail rates. Major arguments in this regard are discussed below.

The APSC/MoPSC argue on rehearing that equalization of nuclear generation costs amounts to setting equalized retail rates among MSU affiliates, and that it flies in the face of Judge Head's conclusion (adopted in the Opinion) that the Commission has no jurisdiction over generating facilities. They claim that the Opinion has effectively emasculated the decisions of the APSC as to need for generating facilities, value of those facilities, return on AP&L's investments, and AP&L's level of operating costs. They further argue that the effect of the decision is to: remove from rate base at the sate level all of the nuclear plants of the operating companies; eliminate from APSC jurisdiction and transfer to FERC jurisdiction most of AP&L's base load power; and remove from APSC regulatory power essentially all control over capacity costs on the AP&L system. The decision, they claim, reflects no balancing or weighing of state interest. The APSC/MoPSC also argue that the ordering of equalization of all nuclear generating costs ignores and is inconsistent with Judge Head's reasoning, adopted by the Commission, for refusing to order systemwide production cost equalization.

The Cities of Conway, *et al.*, argue that production cost equalization would impinge on state regulatory jurisdiction, and strain the State/Federal relationship. They claim that to allow the Commission, through production cost equalization, to force additional rate base and generating facilities on AP&L without prior APSC approval would be contrary to Section 201 of the FPA.

AMAX, Inc., argues that the Opinion will work major changes in AP&L's retail rate base, and result in FERC regulation of generating facilities by transferring local costs from state to state. Further, claims AMAX, the states would be precluded from judging the prudence of Grand Gulf costs and denied any saying the rate of return im-

posed as part of these costs. AMAX contends that cost equalization would have a significant effect on state commissions planning for future power plant construction.

The MPSC and the Attorney General of the State of Mississippi argue that the Commission's decision is contrary to *Pacific Gas and Electric Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190 (1983),[8] in that it impinges on the states' paramount authority in certification decisions regarding need, type, and costs of construction of new generating facilities.

The above arguments must be rejected. Contrary to the assertions or implications made on rehearing, the Commission's Opinion is the result of a careful balancing of the state and Federal interests involved. Our Opinion, 31 FERC at p. 61,344, explicitly adopted Judge Head's discussion, 30 FERC at pp. 65,148-51, in which he found that the Commission has jurisdictional authority to order a form of production cost equalization, but concluded that exercise of this jurisdiction must be tempered and weighed against the policy consideration that generation facilities and retail rate regulation should be left to the states, and that cost equalization should be ordered only if necessary to ensure just, reasonable, and non-discriminatory agreements governing transactions among the MSU subsidiaries. While we disagreed with Judge Head's decision to a certain extent, the interests of the states involved in this case weighed heavily in favor of our decision *not* to adopt full production cost equalization. We thus find our decision fully consistent with the reasoning of Judge Head concerning the need to pay careful heed to the impact our decision would have on the states.

An important point to be emphasized here is that our decision was a limited one. Contrary to the implication of

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[8] Numerous parties opposing any form of cost equalization cited this case in the proceedings below and on rehearing. The case was specifically addressed at p. 61,644 of our Opinion.

the Cities of Conway, *et al.*, we did not order production cost equalization. Nor did we order equalization of all nuclear generation costs, as indicated by the APSC/MoPSC. Opinion No. 234 requires equalization only of nuclear *investment* costs. The result of the Opinion, contrary to the assertion of the APSC/MoPSC, is not equal *rates* for all MSU affiliates. While our decision may increase the System costs subject to FERC jurisdiction, the record is unclear as to the extent this would occur since a substantial portion of System costs are already subject to our regulation.[9] The basic nature of regulatory control retained by the states under previous system agreements remains unchanged. What our decision attempts to do is amend the filed agreements to achieve a non-discriminatory sharing of excess capacity cost imbalances on the integrated System, consistent with the goal of the System Agreement, and to do so with as little intrusion on the States as possible.

Integrated Nature of MSU System

Several parties mischaracterize or misconstrue the Commission's findings concerning the integrated nature of the MSU System. They characterize the Opinion as one which

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[9] For example, Judge Head indicates, 30 FERC at p. 65,149, that *full* production cost equalization (which was *not* adopted here) would remove from the state commissions control of the vast majority of the cost of rendering service within each jurisdiction, and that Staff's full production cost equalization proposal would subject more than 75% of rate base to FERC jurisdiction (citing ER82-483 APSC Ex. 2, pp. 46, 47). (APSC Ex. 2 is the direct testimony of APSC witness Alvin J. Roe.) Other parties, for example OCC and Georgia Gulf, rehearing request, p. 6, claim that more than half of the total costs allegedly "transferred" to FERC jurisdiction under production cost equalization are or would be subject to FERC jurisdiction even absent production cost equalization (citing ER82-483 MPSC Ex. 24). (MPSC Ex. 24 is a 1979 letter to the chairman and chief executive officer of MSU from the president and chief executive officer of LP&L, concerning the advantages and disadvantages of proposed plans to modify the System Agreement.)

finds the MSU System to be a single, "monolithic" entity, which does not consider all relevant evidence as to autonomy on the part of the individual operating companies, and which ignores evidence concerning individual company planning, financing, operation, and actual ownership of System generation units, and representations to state commissions concerning those units.[10]

Both AI and the Cities of Benton, *et al.*, question whether the Commission intends the term "single system" to mean "a group of utilities that have submerged their separate identities, and the interests of their native-load ratepayers, into a common, homogenous physical and economic unit that is indistinguishable from a single utility."[11]

We think it obvious from Opinion No. 234 that the Commission did not intend a meaning such as that quoted above. The Opinion does not describe the MSU System as a "monolithic" entity, nor does it ignore certain autonomous aspects of the individual operating companies.[12] Contrary to the claims of the APSC/MoPSC, AP&L, and the Cities of Conway, *et al.*, the Opinion does not find that all activities of the System and the individual operating companies are controlled by the MSU Board of Directors, nor does it misunderstand the relationship of the companies and the various boards of directors within the System. The Opinion, 31 FERC at pp. 61,645-51, incorporates Judge

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[10] Some or all of these characterizations are made by AI, the APSC/MoPSC, the Cities of Conway, *et al.*, the Cities of Benton, et al., AP&L, and the MPSC.

[11] AI rehearing request, p. 18. The rehearing request of the Cities of Benton, *et al.*, at pp. 7-8, contains an almost identical definition.

[12] The Opinion itself does not even use the term "single system." To the extent Judge Liebman refers to Middle South as a "single" system (*e.g.*, at p. 65,110 of his decision), we do not agree that this implies that there is absolutely no autonomy on the part of the individual companies or that the MSU Board of Directors has total control over the companies.

Head's accurate and thorough description of the interrelationship and overlapping officers and directors among MSU and its subsidiaries,[13] and concludes that the MSU Operating committee (*not* the MSU Board of Directors) makes *major* critical decisions on the System, *primarily* for the System as a whole.

In reaching the above conclusion, the Opinion repeatedly recognizes that the individual operating companies are intimately involved in the planning stages of new generation units on the System. It further recognizes that the Operating Committee (which is composed of representatives of the individual operating companies) makes major System decisions in the form of recommendations to the chief executive officers who, in turn, vote on the recommendations, and that the individual companies make final specific decisions necessary to carry out the overall System plan.[14] This interaction is summed up in the major findings listed at p. 61,650 of the Opinion.

The APSC/MoPSC contend that the Commission relied on selective testimony in finding that the MSU System is a "monolithic" entity, and that the operating companies do not function according to a pattern of autonomy. They claim that the Commission erroneously concluded that a lack of complete autonomy was equivalent to absence of *any* autonomy. AP&L also claims that the Commission's findings are inconsistent with the record and, in this regard, argues that the Commission improperly interpreted Mr. Lupberger's statement (ER82-616 Tr. 347) that the System is operated as tough it were one electrical system under one ownership. This statement referred only to the fact that the units are operated by central dispatch, claims AP&L, and a requirement to pool nuclear investment can-

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[13] We note that p. 61,646 of the Opinion refers to Judge Head's description as being located at 30 FERC pp. 63,141-43. This is a typographical error which should be changed to 30 FERC pp. 65,141-43.

[14] For example, specific timing and location of new generation.

not be predicated on the mere fact that companies use central dispatch.

We disagree strongly with any implication that the testimony relief on in the Opinion is not representative of what is contained in both records concerning the operation of and decisionmaking on the MSU System. A reading of the testimony cited in the Opinion does not reflect a "monolithic" entity, but recognizes the role of the individual companies in System decisionmaking, and the interplay between System and individual company needs. Furthermore, the Commission did not conclude that a lack of complete autonomy was equivalent to the absence of *any* autonomy. We think it clear from our discussion in the Opinion and the evidence cited therein that we were not concluding that the operating companies have no role in decisionmaking and absolutely no autonomy. To the extent any party infers otherwise, the preceding discussion should serve to clarify our position. The fact that there may be *some* autonomy on the part of the individual companies, however, does not lead us to conclude that there is a "pattern of autonomy" such that the individual companies have complete independence and are not subject to major decisions on the system, particularly as to generation additions, being made by and for the System as a whole.

As to AP&L's argument concerning specific testimony of Mr. Lupberger, the reference to that testimony was not intended to imply that Mr. Lupberger was referring to anything other than the physical operation of the System. We further think it is obvious from reading the Opinion as a whole that our decision was not as argued by AP&L, predicated on the mere fact that the companies use central dispatch.

AP&L also argues that, contrary to Opinion No. 234, there is at least one instance where a company (LP&L) refused to build a unit despite a recommendation to do so by the Operating Committee. The evidence cited by AP&L,

however, consists only of Operating Committee minutes showing that the Committee recommended that LP&L build coal units in Northern Louisiana in the early 1980's, and testimony by J.D. Phillips, a senior vice president of AP&L, that there was never any activity regarding these units.[15] This does not reveal an actual refusal to build the units. AP&L cites no evidence as to the reason the units were never constructed.

The APSC/MoPSC contend that the Commission ignored evidence and judicial precedent, relied on by Judge Head, concerning the "pattern of autonomy." Specifically, they claim that we ignored Judge Head's review of decisions by the SEC, AEC, Atomic Safety Licensing Board, the FPC and the FERC, and his conclusion, 30 FERC at p. 65,161, that prior characterizations of the integrated MSU operations do not dictate production cost equalization. They claim that the Opinion also ignored Judge Head's discussion, 30 FERC at pp. 65,162-63, concerning the fact that in Arkansas State proceedings AP&L was required to justify the need for new facilities to meet Arkansas requirements.

Judge Head concluded, 30 FERC at p. 65,161, that "the mosaic of Federal agency decisions relating to the Middle South system leaves no doubt that the system is a closely integrated and coordinated power pooling arrangement from a planning, construction and dispatch standpoint." He concluded that although this finding conceptually lends support to an equalization rationale, it does not of itself constitute such an overriding consideration that it *requires* production cost equalization. We do not consider our decision inconsistent with Judge Head's findings and conclusions in this regard. Our Opinion did not order production cost equalization, and it fully considered the same factors weighed by Judge Head in determining how best to achieve

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[15] ER82-483 Tr. 1200-02; OCC Exh. 23, p. 7; OCC Exh. 24, p. 4; OCC Exh. 26, p. 16; OCC Exh. 30, p. 2.

just, reasonable, and non-discriminatory rates. In reference to the representations made in Arkansas State proceedings concerning AP&L's need for new facilities, our Opinion explicitly recognized these at p. 61,652.

A minor point raised by the APSC/MoPSC concerning our refusal to find that the operating companies are autonomous is our reference at p. 61,651 of the Opinion to the fact that the 1982 System Agreement was changed to provide for decisions by majority vote rather than a two-thirds vote, in order to ensure that one company cannot block a Committee decision.[16] The APSC/Mopsc argue that the Commission fails to note that two companies can still exercise their autonomy to block Operating Committee decisions and that MSS has only a 20% vote such that it cannot impose its will on the Committee. We fail to see the relevance of this argument, since the point to be made is that an *individual* company does not have sufficient autonomy such that it can block a decision against the wishes of other Operating Committee members.

AI, the APSC/MoPSC, and AP&L argue that our decision was made without regard to actual ownership, construction, financing, and operation of generation units, and that it ignores the fact that plant additions other than Grand Gulf become the exclusive asset and economic responsibility of the owning company. They further claim that we ignored the history of AP&L's capacity construction and the fact that it received no financial assistance from other companies when it had financing difficulties with its White Bluff and Independence coal units. Related arguments made by AI and Cities of Benton, *et al.*, are that two provisions of the System Agreements *guarantee* the economic individuality of the MSU subsidiaries under

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[16] To clarify any confusion concerning the testimony cited in our discussion as Tr. 84-85, this refers to LPSC Ex. 86 pp. 84-85, which consists of transcript pages from an MSS proceeding in Docket Nos. ER81-428-000 and EL81-12-000.

the System's pooling practices: (1) the requirement that each company must normally provide its own generating capacity, or contract for capacity, adequate to meet its native load; and (2) the rule that under economic dispatch, while each company agrees to have all system units dispatched in order of efficiency, each pool member has first call on the power and energy produced by its own units.

The Arkansas parties are incorrect that our decision was made without regard to ownership and financing of generating units. The Opinion explicitly recognized, 31 FERC at pp. 61,649 and 650, that each operating company is required by the System Agreement to own or purchase capacity to meet native load. We also recognize, although it was not emphasized in the Opinion, that pool members have first call on the power and energy produced by units which they own. All of these factors were important considerations in our decision not to adopt full production cost equalization, and, to the greatest extent possible, to allow the individual companies to retain the benefits of units which they have been responsible for constructing.

In reference to the parties' claim that pool members are independent because they finance their own construction, two other points should be made. It cannot be ignored that each operating company is financially a part of and dependent on MSU, which supplies equity funds as needed to complete a construction project. A recent example of the financial interdependence of the MSU Companies is Standard and Poor Corporation's lowering of debt issues of *four* MSU Operating companies amid signs that *two* of the units face liquidity problems and that systemwide financial stress is likely to continue.[17] Moreover, page 133H of AP&L's 1982 Form No. 1 indicates that the company now participates with certain other companies of the Middle South System in a System money pool arrangement

[17] *The Wall Street Journal*, April 26, 1985; *Standard and Poor's Creditweek*, April 29, 1985, p. 10, and May 6, 1985, pp. 21-25.

whereby those companies with available funds make short-term loans to other companies in the System have short-term borrowing requirements.

Another argument concerning the operating companies' responsibility for financing their own construction was raised by MP&L. MP&L contends that the Commission erroneously dismissed MSE's role in the System's operation, and erred in finding (Opinion at p. 61,654) that there was no reason to believe the System would not have taken steps similar to those it took for Grand Gulf had other units experienced the same financial problems. MP&L claims this is inconsistent with uncontroverted record evidence to the contrary. In support, MP&L states that in 1975 and 1980, AP&L experienced severe financial difficulties in completing the coal-fired White bluff and Independence units, and the System did not transfer the projects to MSE or otherwise provide financial assistance to AP&L. As a result, claims MP&L, AP&L was forced to stop construction until it could obtain the necessary financing itself.

We fully recognize that the operating companies historically have financed units located in their respective states without direct financial assistance from other System companies. However, there has been no showing that any company previously experienced the magnitude or type of problems associated with Grand Gulf, or was totally unable to finance a unit, as was the case with Grand Gulf.[18] Moreover, the formation of MSE was consistent with the purposes of the integrated MSU power pool operations as embodied in the System Agreement.

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[18] It is true that the Grand Gulf financing problems differentiate that unit from others on the System. We nevertheless do not think it appropriate, as argued by some parties, to equalize only the cost of Grand Gulf, since Grand Gulf originally was planned in the same basic manner as other nuclear units on the System, and all System nuclear units were planned to help meet the overall System goal of achieving a new fuel mix.

The Arkansas parties[19] argue that the Commission's Opinion erroneously "pierces the corporate veil" by disregarding the separate corporate identities of the four operating companies, and used the wrong standards for doing so. They claim that such an extraordinary measure requires a showing that corporate separateness is nothing more than a sham, that the corporate existence has been abused or manipulated to evade the law or gain some advantage contrary to public policy, or that MSU has used the separate corporate identities of MSE to frustrate or avoid any purpose of the FPA. Many of the parties cite *Nantahala Power and Light Co.*, Opinion No. 139, 19 FERC ¶61,152 (1982), as defining the criteria for piercing the corporate veil. They also argue that the Commission based its decision solely on the fact that the operating companies are commonly owned.

We do not view our decision as one involving a formal "piercing of the corporate veil" and consider *Nantahala* to be distinguishable in this regard. *Nantahala* involved a non-jurisdictional entity, Aluminum Company of America (Alcoa), and two subsidiary utilities, Nantahala and Tapoco, Inc. Nantahala served as a public utility while Tapoco was an industrial power supply source for Alcoa. In a complaint proceeding before us, a Nantahala customer had claimed that Alcoa had used its subsidiaries for its own benefit, by diverting for its private use hydroelectric power dedicated to public service. The customer claimed that all three companies had violated the FPA, and asked the Commission to pierce the corporate veil between the two subsidiaries and treat them as one entity for ratemaking purposes. We refused to do so because there was no evidence that Alcoa had used the separate corporate identities of the two subsidiaries to frustrate the purposes of the

[19] The Cities of Benton, *et al.*, AI, AP&L, the Arkansas and Missouri Congressional Delegations, and the Cities of conway, *et al.*

FPA, *or* that the companies operated as an integrated system.

The facts of *Nantahala* are clearly distinguishable from those here. The question before us is not whether MSU has used the separate corporate identities of the operating companies to frustrate the purposes of the FPA. Rather, the issue is how to achieve just, reasonable, non-discriminatory and non-preferential rates among highly integrated companies, pursuant to jurisdictional pooling agreements which have been filed with us. Our decision does not, as argued by some parties, rest on the mere fact that the operating companies are commonly owned. However, because of the nature of the MSU System, and the types of agreements before us, any resolution cannot ignore the interrelationship of the MSU companies, particularly regarding System decisionmaking, or the interrelationship of the agreements governing pooling transactions.

AI, the Cities of Conway, *et al.*, and the Cities of Benton, *et al.*, argue that in finding MSU to be a "single system," the Commission misjudged the nature of the System and its coordinating agreements. They claim there is no evidence to suggest that the actions of the operating companies differ materially from those of unaffiliated utilities that elect to interconnect, economically dispatch generating facilities, and engage in joint reserve planning. The fact that the operating companies are commonly owned, they argue, does not convert actively coordinating systems into a single system. We think these arguments are misplaced. The case before us involves affiliates, and we would be remiss to ignore this fact in reviewing transactions and agreements among those affiliates. The types of transactions that take place among interconnected nonaffiliates is not before us and is not relevant to our consideration here. Moreover, our decision does not hinge on the single factor of common ownership, but rather focuses on a variety of factors including the manner in which decisions are made

by the commonly owned affiliates, and for whose primary benefit those decisions are made.

Lastly, we address the arguments of AP&L, the Cities of Benton, *et al.*, the APSC and I, that if the operating companies operate as a single entity, then the presence of wholesale transactions vanishes, any transfer of power among the companies becomes an intracompany transfer, and Commission jurisdiction is voided. As previously discussed, our Opinion does not find MSU to be a single, monolithic entity, with total disregard for the existence of the individual operating companies. The transactions under both the System Agreement and the UPSA clearly are sales for resale in interstate commerce, despite the fact that the companies operate a physically integrated system and plan construction primarily to meet the needs of the System as a whole, and they remain subject to our jurisdiction.

The Opinion No. 234 Allocation

On rehearing, almost all parties object to the Grand Gulf allocation adopted in Opinion No. 234. To the extent the arguments of the parties may not have been adequately addressed in the Opinion or in portions of the initial decisions adopted in the Opinion, the major arguments are addressed below.

AP&L argues that the filed UPSA is a rational disposition of Grand Gulf power, based on recognized power planning principles. The result of nuclear investment cost equalization, claims AP&L, would be that the production costs of each company would no longer be based on actual investment and expenses incurred by the company to serve its customers, but instead on the company's own fossil fuel unit costs and an average of the investment for all nuclear units. The resulting rates for AP&L would not bear a direct relationship to its actual investment and expenses. AP&L further argues that the Opinion is inconsistent with the purpose and effect of prior coordination agreements

and Commission precedent, that equalization has never been an objective of the System Agreements, and that the FPA does not require equalized costs.

The APSC/MoPSC also support the filed UPSA, and contend that the Commission undertook no in-depth analysis of the unit sales plan with respect to the appropriateness of the plan from a power supply standpoint. They argue that the allocation was improperly made from the perspective of 1983 rather than from the more appropriate 1979-80 time frame when the unit sales plan was adopted. The analysis, they contend, should be based on a 1979 perspective and focus on: the objectives in making the sales of Grand Gulf entitlements; whether those objectives were just and reasonable; and whether the sales agreement serves those objectives. The APSC/MoPSC further contend that the Commission erroneously concluded that one of the System goals was to equalize generating costs, and that the allocation adopted is in error because it ignores coal, gas and hydroelectric capacity on the System and does not serve System goals.

Contrary to the APSC/MoPSC's contention, and the implication of AP&L, our Opinion did not conclude that a goal fo the MSU System was to equalize generating costs. Rather, it specifically noted, at p. 61,646, the intention of the System Agreement to provide a basis for equalizing among the companies any *imbalance* of costs associated with the construction, ownership, and operation of such facilities as are used for the mutual benefit of all the companies. The Opinion also recognized, at pp. 61,646 and 61,656, all of the major goals and objectives of the System Agreement, including the power supply goals of moving toward a new fuel base of coal and nuclear power and having each company obtain a proportionate share of base load generating units either by ownership or purchase. Our decisions, at p. 61,656, specifically found the adopted allocation would be consistent with and promote the System's major objectives.

We disagree with the APSC/MoPSC's contention that the allocation should have been made from the perspective of the 1979-80 time frame when the UPSA initially was adopted. The salient issue here is not whether the agreement was reasonable when made, or whether it met the System objectives at the time it was made. Rather, the principal inquiry is whether the allocation is appropriate based on the evidentiary record that was subsequently developed. In this particular case, we are dealing with a situation involving changing factors unique to nuclear plant construction, and the hearing in ER82-616 was to set rates for a unit which had not yet gone into commercial operation. We therefore think it was entirely appropriate to focus on the more recent record data in the ER82-616 proceeding for the specific purpose of apportioning Grand Gulf costs under the UPSA.

In reference to AP&L's argument that the adopted allocation will result in costs no longer based on actual investment and expenses, it is true that individual companies will be responsible for portions of a unit in which they themselves did not actually invest. The point is, however, that if a unit is built to meet overall System goals, then the individual company will benefit from that unit either directly or indirectly, and may properly bear a portion of the costs of the unit. Further support for an allocation that is not based strictly on a company's own investment and expenses in these proceedings is the individual company's contractual agreement (the System Agreement) to bear a portion of any imbalance of costs resulting from such a unit.

Several Arkansas parties argue that the Commission erroneously imposed a Grand Gulf allocation on AP&L without finding that AP&L *needed* such capacity.[20] In this

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[20] AI, the Arkansas and Missouri Congressional Delegations, the Cities of Benton, *et al.*, and the APSC. The MLSC also raises this point as it relates to Mississippi ratepayers.

regard, AI and the Cities of Benton, *et al.*, also contend that the Commission erred in relying on AP&L's former involvement in the Grand Gulf project, but disregarding AP&L's limited contractual obligation to purchase Grand Gulf power on an as-needed basis. AP&L's obligation, they state, was only to take such amount of Grand Gulf as it needed, as determined by whether it was "long" or "short" under the MSU System Agreement. They claim the Commission disregarded the set of amended agreements and enforced the original ones, oblivious to the fact that AP&L had, at a maximum, bargained for no more than a small percentage share of Grand Gulf.

The argument that allocation of Grand Gulf costs should be based on whether individual companies "need" Grand Gulf capacity must be rejected. We reaffirm that the Middle South companies appropriately approach power planning on a systemwide basis, whereby the individual companies' needs are the component parts of the System power plan. Implementation of the System plan, however, requires that the individual companies' needs be subsumed by the greater interests of the entire System. Moreover, the System Agreement requires an equitable sharing of cost imbalances associated with facilities used for the mutual benefit of all companies. The record evidence relied upon in Opinion No. 234 establishes that Grand Gulf was built primarily to serve the System as a whole and to meet the System goal of obtaining a greater proportion of nuclear capacity. Our task, therefore, is one of allocating costs consistent with the mandate of the Federal Power Act, and the allocation of Grand Gulf power must rest not on the "needs" of an individual company, but rather on the principles of just, reasonable, non-discriminatory, and non-preferential rates Opinion No. 234 follows the mandate of the FPA and is consistent with the intent of the System Agreement.

The Mississippi parties[21] contend that Opinion No. 234 fails to examine the impact and inequities of the adopted allocation on Mississippi ratepayers, and provides no rate relief for those ratepayers.[22] They also claim that if the Commission accepts Judge Liebman's findings that the filed 31.63% Grand Gulf allocation to MP&L would cause MP&L's rates to increase "dramatically" and cause "serious detriment" to Mississippi ratepayers, then the 33% allocation to MP&L adopted in the Opinion (and by Judge Liebman) is even more detrimental. If 31.63% is unjust and unreasonable, they contend, then 33% cannot be just and reasonable. They further argue that the Opinion will impose unlawful cross-subsidization among the companies. In this regard, the Mississippi Attorney General specifically argues that MP&L would be subsidizing companies with deficient capability responsibility since, as a long company, MP&L would be required to take and pay for the high capital costs of Grand Gulf and sell its excess generation at a price based on the low capital costs of its oil and gas-fired generation.

Related to the above arguments is the contention of some of the Mississippi parties that the adopted allocation is discriminatory because it does not result in each operating company bearing the same cost per kWh for Grand

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[21] MI, the MPSC, Representative Webb Franklin, the Attorney General of Mississippi, MP&L, and the MLSC.

[22] MP&L claims the decision will result in costs to MP&L that will be approximately 125% of the average system costs, that MP&L will pay $2,156 per kW for service from the same MSU nuclear units that will serve AP&L for $848/kW, and that the adopted allocation discriminates against three of the operating companies in favor of AP&L. Representative Webb Franklin claims the decision will result in MP&L paying more than 2.5 times as much per kW for nuclear capacity as would AP&L. The MLSC claims the decision will result in pricing electricity beyond the means of the average elderly or poor person in Mississippi, and will render the concept of "universal service" in Mississippi null and void.

Gulf energy, and results in different prices to similarly situated customers despite the fact that the seller's costs are the same.[23] MP&L and Representative Webb Franklin argue that Judge Head's allocation is more equitable because it would result in each customer bearing identical costs per kWh for Grand Gulf energy. MI also claims discrimination on the ground that the adopted allocation ignores the disparity in the size of the MSU operating companies.[24]

Another related argument made by MP&L, the MAG, and MI is that the Opinion erroneously results in allocating costs of the nuclear units, but not associated benefits.[25] MP&L also claims that the decision ignores the disparities in the costs of non-nuclear capacity, and that limiting relief to nuclear units unfairly excludes MP&L from the low busbar costs of energy from the lower-cost conventional plants of the system. A proper rolled-in cost allocation, claims MP&L, would assign each company a proportionate blend of high and lower nuclear costs in the same proportion as that customer obtains the benefits of the facilities.[26]

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[23] MP&L, Representative Webb Franklin, MI, and the MPSC.

[24] In support, AI states that an allocation of $1 of Grand Gulf costs to LP&L would be spread over three times as much customer demand as an allocating of $1 of such costs to MP&L, yet the Commission would allocate over twice as many dollars to MP&L as to LP&L.

[25] The MAG claims that the cost of System nuclear capacity to the companies will range from a low of $804/kW for AP&L to a high of $2,222/kW for NOPSI and MP&L, while the average cost of such capacity was $1,344/kW. (These figures are based on the MAG's Schedule 1 attached to his request for rehearing.) He claims that MP&L would be paying to receive entitlement to 612 MW of nuclear capacity but would actually receive only 370 MW, whereas AP&L would pay for 1,344 MW but would receive 2,245 MW of nuclear entitlements.

[26] MP&L claims that it will pay some 15% of the aggregate cost of all four nuclear units, but receive the benefit of 9.5% of System nuclear capacity.

The City of New Orleans similarly contends that the decision fails to definitively indicate its impact on the individual companies and their consumers, that it erroneously allocates the costs of nuclear investment while failing to provide matching benefits,[27] that it is discriminatory because it does not result in each consumer paying the same rate for allocated capacity as is paid by every other consumer, and that it discriminates against the smaller MSU companies.[28]

First, we wish to clarify that our intent in adopting a form of very limited cost equalization was not to eliminate all cost disparities on the MSU System or to have the companies necessarily pay the same average cost per kWh for all of their energy. It is true that costs were roughly equalized among the companies under previous operating agreements, although there has never been a stated intent to equalize all costs. As previously recognized herein, the intent of the System Agreements has not been to specifically equalize costs, but rather to equalize any imbalance of costs associated with facilities used for the mutual benefit of all the companies. Where different state regulatory bodies give different treatment to various rate elements, it is a natural consequence that retail rates among the companies will differ. This would be true even under full production cost equalization. What our decision purports

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[27] In support, CNO states that the Opinion's approach will result in a 2.7¢/kWh difference between the highest (NOPSI) and lowest (AP&L) cost companies, as compared to 2.4¢/kWh under Judge Head's decision. It also claims that under Opinion No. 234, NOPSI will bear an 8% share of nuclear investment costs but receive only 4.8% of the capacity produced and energy generated by that total nuclear investment; MP&L will bear 15% of the cost but receive only 9.5% of the benefits; and AP&L will bear 33% of the costs but receive 53.5% of the benefits.

[28] CNO argues that the smaller companies, NOPSI and MP&L, will be discriminated against because they will receive energy only from Grand Gulf, while AP&L will continue to receive all of the ANO 1 and 2 energy, and LP&L will receive all of the Waterford 3 energy.

to do is to eliminate drastic rate disparities at the wholesale rate level which are associated with units used for the mutual benefit of all companies, and to so do in a manner which disturbs the historical operation of the System as little as possible, and which allows the individual companies to retain as fully as possible the benefits of units they have financed and constructed. In other words, we have sought to achieve an equitable balance between the interests of the individual companies and the System as a whole, consistent with the System Agreement.

We reject the arguments that our allotments of Grand Gulf cause price or other discrimination because they produce a different Grand Gulf cost or price per kWh for each operating company, whereas Judge Head's approach produces a nondiscriminatory, uniform Grand gulf cost per kWh. These allegations of discrimination are unfounded because they are based on references to the *total* kWh's (i.e., kWh's not only from Grand Gulf but from all sources) for each operating company rather than Grand gulf kWh's. Of course, the rate for Grand Gulf service applies only to Grand Gulf kW's and kWh's

Our responsibility is to set just, reasonable, and nondiscriminatory rates at the wholesale level. The fact that the Grand GULF Gulf allocation adopted by us may result in ultimate costs per total kWh which are different for each operating company does not constitute undue discrimination at the sale for resale level. Opinion No. 234 adopted a Grand Gulf allotment method designed to equalize the total cost of all nuclear investment per kW of total average demand for each operating company. The resulting Grand Gulf kWh sales will be uniformly priced to each operating company in terms of Grand Gulf kWh's of energy. There is no price discrimination because there is a single formula rate in effect for all transactions, and each Grand Gulf kWh will cost each operating company the same amount. No other proposal equalizes the total nuclear

investment cost per kW of average demand and uniformly prices Grand Gulf kWh's.

The adopted allocation will have a substantial impact on all four of the operating companies, not just on Mississippi. We recognize that there may be an inconsistency in Judge Liebman's finding, 26 FERC at p. 65,107, that the filed 31.63% UPSA allocation to MP&L would cause serious detriment to the Mississippi (and Louisiana) ratepayers, and his ultimate conclusion that MP&L should be allocated 33% of the UPSA. Judge Liebman's decision did not directly address this alleged discrepancy. However, a careful reading of his discussion concerning the discrepancy in rates indicates that the largest discrepancy under the filed UPSA would be as to LP&L,[29] and that his focus appeared to be primarily on LP&L. Whether or not there is a discrepancy in the judge's findings, we wish to clarify that we consider a 33% allocation to MP&L to be equitable, particularly in view of the fat that the result of the Opinion is that all three major geographical areas served by the MSU System will share similar Grand Gulf cost burdens: AP&L—36%; MP&L—33%; and LP&L/NOPSI—31%.

We disagree that the allocation will result in unlawful cross-subsidization. The Grand Gulf allotments represent each company's *pro rata* share of the responsibility for meeting the System goal of moving away from oil and gas toward a new fuel base of nuclear and coal generation. In this regard, we also reject the arguments made by Mississippi parties and CNO that we have erroneously focused only on nuclear generation.[30] While we recognize that the

[29] Preceding Judge Liebman's statements is a table which shows that MSE's proposed allocation of Grand Gulf 1 (the filed UPSA) would result in the parties having responsibility for total nuclear capacity (including Waterford 3) in the following amounts: AP&L—$0.9 billion; LP&L—$3.4 billion; MP&L—$0.8 billion; and NOPSI—$0.7 billion.

[30] MP&L and MI argue that the cost of energy from the ANO units is less than that from recently built coal-fired units on the System,

System goal was to move toward coal as well as nuclear base load generation and that energy from the ANO nuclear units may be less costly than that from some coal-fired units, we nevertheless think it appropriate to focus only on nuclear units because of the unique nature of and industry-wide problems associated with nuclear construction.

MP&L argues that the cost escalations of Grand Gulf 1 and Waterford 3 might justify focusing exclusively on them, but that they do not support distinguishing the lower cost ANO 1 and 2 units from the coal-fired base load units. CNO similarly argues that the ANO units are not of the same cost caliber as Grand Gulf, but further argues that the fact that some plants are enormously expensive does not justify equalization. Although it may be true that the ANO nuclear units are not of the same cost magnitude as the newer nuclear units, we think it appropriate not to attempt to segregate the nuclear units, particularly in view of the fact that to a great extent it was imply a matter of timing as to which company built the first cheaper nuclear units.

In reference to the arguments that the Opinion erroneously results in allocating nuclear costs but not associated benefits, a major objective of our decision was to fairly apportion nuclear investment responsibility and to do so via appropriate Grand Gulf allotments. We do not think it proper, unless necessary to achieve just, reasonable, and non-discriminatory results, to re-apportion the

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and that the exclusive focus on nuclear generation is erroneous. MI asserts that the adopted allocation will not promote the System's objective to move toward coal *and* nuclear generation.

MI, MP&L and Representative Webb Franklin claim that if all plants are "system" plants, then it is inconsistent not equalize all production costs. MP&L also argues that the exclusion of coal, gas, and oil-fired units implies that those units separately serve a different customer group than is served by the MSU nuclear units.

benefits of the older nuclear units which have been in service for some time and have already been absorbed by AP&L's native load. As to the Grand Gulf allotments themselves, the companies will receive the benefits associated with the costs they pay for Grand Gulf.

Several Louisiana parties generally support the Commission's findings and conclusions, but argue that we erred in failing to adopt full production cost equalization.[31] OCC and Georgia Gulf argue that the Opinion incorrectly found that production cost equalization would be a substantial change from previous System cost allocation. We disagree. Full production cost equalization would be a substantial change from the allocation methodologies historically used on the MSU System. As previously discussed throughout this section, the adopted allocation is an attempt to equalize the imbalance of cost on the System with the least disruption possible to the historical operation of the System.

If nuclear investment cost equalization is retained, the Louisiana parties request that we use updated cost data for Grand Gulf 1 and Waterford 3 in applying our methodology. This request previously was made and denied at p. 61,657 of our Opinion. We again decline to use updated cost figures because both the cost estimates and demand projections used in Opinion No. 234 were reasonable when made, and it is necessary to use some fixed point in time in order to provide finality to a proceeding, rather than continuously updating or using spot adjustments.

As in the proceedings below, the parties on rehearing continue to advocate a variety of positions and alternative positions including: accepting the 1982 System Agreement as filed; retaining the 1973 System Agreement's participation unit concept; adopting Judge Head's recommended allocation; adopting full production cost equalization; ac-

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[31] OCC and Georgia Gulf Corporation, the LPSC, LP&L and NOPSI.

cepting the Opinion No. 234 allocation allocation; or adopting variations of the above. The majority of proposals have been analyzed either in the initial decisions or in the Opinion, and one fact is clear: none of the proposals is without flaws and none is totally acceptable to any party. At the risk of being repetitive, we believe that Opinion No. 234 results in an allocation scheme that is not at one extreme or the other, but rather represents a balancing of the need to provide an equitable sharing of the investment costs of units that have (or could have) become unforeseeably high due to the unique problems associated with nuclear construction, and the need to recognize the efforts of individual companies on the System and allow them to retain the benefits of units they own to the fullest extent possible.

A final point we wish to emphasized is that the parties have voluntarily agreed to pool resources and share certain costs. They have already voluntarily agreed, under the UPSA in conjunction with the 1982 System Agreement, to allocate Grand Gulf. What our opinion does is to alter in as limited a means as possible the agreed-upon cost scheme, in order to achieve just, reasonable, non-discriminatory and non-preferential rates.

Miscellaneous Rate Issues

Several parties seek rehearing on miscellaneous rate issues in Docket No. ER82-616 MSE seeks rehearing on the issue of rate of return, customer service and sales expenses, use of the UPO and ELG depreciation methods, the annual amount of nuclear decommissioning expense, use of an external sinking fund for accumulating decommissioning amounts, and use of an algebraic tax formula for calculating income tax expense. The LPSC seeks rehearing on the issues of rate or return and cash working capital. AP&L seeks rehearing on use of the UPO depreciation method.

The rehearing arguments raise no matters not previously considered, or that would warrant departure from

our decision on the above issues. However, we wish to briefly address MSE's arguments concerning use of the UOP depreciation method. MSE claims the Commission mistakenly believed that the shakedown period of Grand Gulf 1 was not likely to be more than 12 months, but that the record shows at Tr. 319-20 that the initial shakedown could be two to three years, and might extend up to five years. MSE states that it expects to shut the unit down in mid-May 1986, that it may be shut down for a lengthy period of time, and that the shakedown won't be completed until the unit is restarted. The requirement that MSE request to extend the time for using the UOP method in a future proceeding, at the expiration of 12 months, asserts MSE, creates uncertainty in the eyes of MSE, its and investors and customers, regarding the right to continued use of the UOP method thereafter if shakedown has not been completed.

The transcript pages to which MSE cites contain cross-examination of MSE witness Utley. Mr. Utley states that the stabilization period for Grand Gulf is a range of two to three years, perhaps slightly longer. When asked his basis for stating that the period is two or three years, his reply was:

> Just a personal view, to give you an idea of what I think we're talking about as a stabilizing period. I think circumstances would tell us what that would be. But certainly it's not a period longer than five years, and certainly somewhat shorter than that. Tr. 320.

We do not think this testimony provides sufficient certainty as to what length the initial shakedown period will be. Having given MSE the opportunity to come in in future proceedings and seek to extend the time in which to use the UOP method, we also do not accept the argument that there is too much uncertainty in the eyes of MSE's customers and investors. MSE will be allowed to recover its full depreciation expense whether or not the UOP method

is used. Furthermore, the UOP method creates more uncertainty for the customers and investors than does the conventional straight-line depreciation method in that it does not assure the company of a fixed annual recovery of depreciation. MSE's rehearing arguments therefore are rejected.

Requests for Recusal

AP&L, the Attorney General of Mississippi, and the MPSC argue that former Commissioner Oliver G. Richard erroneously failed to recuse himself from these proceedings. The Attorney General claims that the recusal decision should have been made by the full commission or an independent presiding judge and, further, that the wrong legal standard was applied concerning the recusal. We do not find any merit to these arguments, and they are rejected.

Interventions

OCC and Georgia Gulf request that the Commission clarify that it has granted their separate petition to intervene out-of-time, filed March 5, 1985, in the above dockets, and that Georgia Gulf has been admitted as a party intervenor in both proceedings. Mississippi Industries asks the Commission to clarify the Opinion to state that parties to either or both dockets governed by the Opinion may address all issues of fact and law on rehearing or, in the alternative, to grant it leave to intervene out-of-time in Docket No. ER82-616. Jefferson Parish, Louisiana, also asks that we clarify the Opinion so as to remove any doubt that Jefferson Parish was granted late in intervention in each of the above dockets.

We hereby clarify Opinion No. 234 to state that the above parties have been granted intervention in both Docket Nos. ER82-483-000 and ER82-616-000.

The Commission orders:

(A) The requests for rehearing filed in these dockets on July 3, 11, 12, and 15, 1985, are denied.

(B) Opinion No. 234, 31 FERC ¶61,305 (1985), is clarified in accordance with this Opinion.

(C) Requests for late intervention are granted in accordance with this Opinion.

(D) The request for rehearing of our denial of a stay of Opinion No. 234 (32 FERC ¶61,207 (1985)), filed by AP&L on September 3, 1985 in Docket Nos. ER82-616-028 and ER82-483-024, hereby is denied in accordance with our order denying similar requests for rehearing, issued September 3, 1985, 32 FERC ¶61,346.

APPENDIX C

CITED AS "31 FERC ¶. . . ."

[¶ 61,305]

Middle South Energy, Inc., Docket Nos. ER82-616-000 and ER82-483-000

Opinion No. 234; Opinion and Order Setting Just, Reasonable, and Non-Discriminatory Rates

(Issued June 13, 1985)

Before Commissioners: Raymond J. O'Connor, Chairman; Georgiana Sheldon, A. G. Sousa, Oliver G. Richard III and Charles G. Stalon.

[Note: Initial Decision Concerning Sales of Power From the Grand Gulf Nuclear Generating Plant of the administrative law judge, issued February 3, 1984, appears at 26 FERC ¶ 63,044. The Initial Decision of the administrative law judge, issued February 4, 1985, appears at 30 FERC ¶ 63,030.]

Appearances

Docket No. ER82-616-000

Elizabeth H. Ross for Missouri Public Service Commission

Hiram C. Eastland, Jr. and *Champ Terney* for Mississippi Public Service Commission

Richard M. Merriman, Robert S. Waters, James K. Mitchell, Lisa H. Powell and *William D. Meriwether,* for Middle South Energy, Inc.

Nathan Norton for Arkansas Public Service Commission

John L. Maxey and *Michael Raff* for Mississippi Legal Services Coalition

Frank Spencer and *Bill Allain* for the Mississippi Attorney General

Paul L. Zimmering, Michael R. Fontham, Marshall B. Brinkley, and *Bruce M. Louiselle* for Louisiana Public Service Commission

David N. Carne and *Peter Goldsmith* for Cities of Conway and West Memphis, Arkansas

Bernays Thomas Barclay, John B. O'Sullivan, and *Rigdon H. Boykin* for International Paper Company

Glen L. Ortman, Cliton A. Vince, and *Gregg D. Ottinger* for the City of New Orleans

Robert H. Wood, Jr. and *Linda Lipe Gleghorn* for the Arkansas Public Service Commission

Hubbard T. Saunders and *Bennett E. Smith* for the Mississippi Public Service Commission

Roger W. Giles and *Garry S. Wann* for the Office of Attorney General, State of Arkansas

Earle H. O'Donnell and *Robert R. Morrow* for Occidential Chemical Corporation

Richard M. Troy for the State of Louisiana

Charles Reusch, Robert L. Woods, James E. Rogers, Michael Small and *Maureen Thompson* for the Staff of the Federal Energy Regulatory Commission

Docket No. ER82-483-000

Richard M. Merriman, Robert S. Waters, Lisa H. Powell, William D. Meriwether, Jr., and *Floyd L. Norton, IV,* for Middle South Services, Inc.

Steve L. Riggs, Jerry D. Jackson, Robert J. Glasser, and *Carl D. Hobelman* for Arkansas Power & Light Company

Andrew P. Carter, Eugene Taggart, and *Willie J. Nunnery* for Louisiana Power & Light Company and New Orleans Public Service, Inc.

George F. Bruder, James K. Child, Jr., and *Henderson S. Hall, Jr.* for Mississippi Power & Light Company, Louisiana Power & Light Company, and New Orleans Public Service, Inc.

Robert Wood, N. M. Norton, Jr., Wallace L. Duncan, J. Cathy Lichtenberg, and *Janice L. Lower* for Arkansas Public Service Commission

Steve Clark, Garry W. Wann, Robert H. Wood, Jr., and *Roger Giles* for the Arkansas Attorney General

Richard M. Smith for the Congressional Delegations of the States of Arkansas and Missouri

Zachary D. Wilson for the Cities of Benton, North Little Rock, Osceola, and Prescott, Arkansas and Farmers' Electric Cooperative Corp.

A. Hewitt Rose, Charles F. Wheatley, Jr., Michael J. Thompson, and *Peter A. Goldsmith* for Conway and West Memphis, Arkansas

Michael E. Fontham, Marshall B. Brinkley, and *Paul L. Zimmering, Jr.* for Louisiana Public Service Commission

David B. Robinson and *Mariano G. Hinojosa* for Louisiana Attorney General

David B. Robinson for Louisiana Congressional Delegation

Honorable W. J. (Billy) Tauzin for W. J. Tauzin

Clinton Vince, Glen Ortman, Paul Nordstrom, and *Greg Ottinger* for the City of New Orleans

Champ Terney, Hiram C. Eastland, Jr., Bennett Smith, Glen Hays, Donna Allday, Edwin Lloyd Pittman, and *Jay Stewart* for Mississippi Public Service Commission

John L. Maxey, II for Mississippi Attorney General

Honorable Wayne Dowdy and *Webb Franklin* for Wayne Dowdy and Webb Franklin

Martin C. Rothfelder for the Missouri Public Service Commission

James M. Fisher and *Richard W. French* for the Missouri Office of the Public Counsel

James B. Selna, David T. Beddow, and *Donald T. Bliss* for Amax

John B. O'Sullivan, Robert F. Shapiro, and *Bernays T. Barclay* for International Paper Company

Earl H. O'Donnell and *Robert R. Morrow* for Occidental Chemical Corp. and Georgia Pacific Corp.

Paul H. Keck and *Brian R. Gish* for Mississippi Industries

Alfred J. Cheplin, Jr. for Mississippi Legal Services Coalition

Bonnie S. Blair and *Robert McDiarmid* for Municipal Energy Agency of Mississippi

John Nassikas, James L. Trump, J. Mark Davis, Alston Jennings, Jr., and *Kenneth A. Barry* for the Arkansas Industries

William A. Chesnutt and *Henry R. MacNicholas* for Union Carbide Corp.

Thomas L. Blackburn and *Charles Reusch* for the Staff of the Federal Energy Regulatory Commission

[Opinion No. 234 Text]

Pending before the Commission are briefs on exceptions to two initial decisions in dockets which are not consolidated but which have overlapping issues concerning the appropriate allocation of capacity costs incurred on the Middle South Utilities (MSU) system. Docket No. ER82-

483 involves a 1982 System Agreement which sets forth the terms and conditions for transactions among MSU's four wholly owned subsidiaries, Louisiana Power & Light Company (LP&L), Mississippi Power & Light Company (MP&L), Arkansas Power & Light Company (AP&L), and New Orleans Public Service, Inc. (NOPSI). Docket No. ER82-616 involves a Unit Power Sales Agreement under which Middle South Energy, Inc. proposes to sell to LP&L, MP&L, and NOPSI all of the capacity and energy from its Grand Gulf Nuclear Station located in Port Gibson, Mississippi.[1]

The initial decision in ER82-616 was issued on February 3, 1984. 26 FERC ¶ 63,044. The initial decision in ER82-483 was issued on February 4, 1985. 30 FERC ¶ 63,030. This opinion addresses both initial decisions. Section I addresses the major cost allocation issues contained in both dockets, Sections II and III separately address the remaining rate issues, except for rate of return, in each of the dockets, and Section IV addresses rate of return for both dockets.

At the outset, we emphasize that these dockets present some extremely difficult and controversial cost allocation issues which have no easy answers. There appears to be no proposed resolution in the records that would please all parties. We therefore wish to express our disappoint-

[1] Also pending before the Commission is a proposed settlement agreement filed on January 4, 1985, as revised on February 5, 1985, by AP&L, LP&L, MP&L, NOPSI, Middle South Energy, Inc., and Middle South Services, Inc., seeking to resolve all issues in the two dockets. Comments on the settlement were received from 22 participants, almost all of whom opposed the settlement as filed but indicated that they favored resolution of the proceedings by settlement. On February 22 [30 FERC ¶ 61,196], the Commission issued an order appointing a three-judge panel to preside over further settlement negotiations. The three-judge panel reported to the Commission on March 14, 1985, that further settlement procedures at that time would be fruitless, and that the Commission should go forward with its decision. The January 4, 1985 settlement, as revised on February 5, 1985, is hereby rejected.

ment in the fact that, despite every encouragement and opportunity, the parties were unable to unanimously resolve their differences. We have reached a decision which we believe will achieve an equitable result and is supported by the records. That decision is to approve the 1982 System Agreement as filed in Docket No. ER82-483 (with the exception of certain small modifications addressed in Section III, *infra*), and to adopt the Grand Gulf allocation recommended by the presiding judge in Docket No. ER82-616.

I. Grand Gulf Allocation and Production Cost Allocation

This section contains a general description of the two dockets, the initial decisions, the major legal, factual, and policy issues raised concerning cost allocation, an analysis of the facts and arguments, and a resolution of the issues raised. The reader is referred to the initial decisions for further background information.

A. Docket No. ER82-616 (Grand Gulf Agreement)

The major issue in Docket No. ER82-616 is who among the four MSU operating companies should bear the cost of the Grand Gulf Nuclear Electric Station, and in what proportions. Grand Gulf is located in Port Gibson, Mississippi. When completed, it will consist of two 1,250 MW generating units. Unit No. 1 (Grand Gulf 1) is expected to begin commercial operation on July 1, 1985. Unit No. 2 (Grand Gulf 2) is not expected to begin operation until 1989.[2]

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[2] Unit No. 1 was previously scheduled to begin commercial operation in the first quarter of 1985. On May 23, 1985, the Commission was notified by letter from MSS that the unit is now scheduled to begin commercial operation at 12:01 on July 1, 1985. Construction of Unit No. 2 was suspended in 1979 pending completion of Unit No. 1 and the system has not reached a decision as to when it will commence construction of Grand Gulf 2. (26 FERC at p. 65,122.)

Ninety percent of the Grand Gulf units is owned by Middle South Energy, Inc. (MSE), a wholly owned subsidiary of MSU.[3] The units were originally planned by MP&L, but MSE was created to facilitate the financing of the units when MP&L determined that it would be unable to do so. This docket began when MSE filed a Unit Power Sales Agreement (UPSA) which provides for the sale of the output of both nuclear units for their lives under a formula, or cost of service, rate for determining the price of Grand Gulf's output. Under the agreement, all of the output of both units would be sold to LP&L, MP&L, and NOPSI according to certain entitlement percentages. The entitlement percentages for Unit No. 1 would be: LP&L—38.57%; MP&L—31.63%; NOPSI—29.80%. Although all four MSU operating companies are signatories to the UPSA, none of the output would be sold to AP&L under the agreement as initially proposed.

The major objection of the numerous intervenors in the docket concerns MSE's decision to sell all of Grand Gulf's output only to LP&L, MP&L, and NOPSI, and none to AP&L. The costs of Grand Gulf are enormous. The cost of MSE's 90% share is estimated at approximately $3 billion, resulting in a cost per kW of approximately $2,500. LP&L, MP&L, NOPSI, and their customers want AP&L to share some of the burden of these costs.

The Initial Decision

Presiding Judge Liebman concluded that the evidence was overwhelming that the Middle South system is a single integrated and coordinated electric system operating in Louisiana, Mississippi, Arkansas, and Missouri. He found that the Grand Gulf project was initiated in the 1970's to meet the then projected load demand of the *system* and not just the load of any Middle South operating company

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[3] MSE sold 10% of Grand Gulf to the South Mississippi Electric Power Association.

or companies, and further that every unit on the Middle South system had been constructed to meet system load. Therefore, he concluded that the costs of Grand Gulf capacity and energy should be shared equitably by all four operating companies and their customers.

After finding MSE's proposed entitlement percentages unjust, unreasonable, and unduly discriminatory, the judge adopted the allocation proposal of the Louisiana Public Service Commission (LPSC) and Occidental Chemical Corporation (OCC). Under their proposal, each operating company would be allocated a share of the cost of nuclear capacity on the MSU system roughly in proportion to each company's relative share of system demand.[4] The Grand Gulf allocation percentages adopted by the judge, contrasted to those proposed by MSE, are:

Entitlement Percentages—Unit No. 1

Company	*As filed by MSE*	*As recommended in Initial Decision*
AP&L	–0–%	36.00%
LP&L	38.57	14.00
MP&L	31.63	33.00
NOPSI	29.80	17.00
	100.00%	100.00%

The effect of the judge's decision was not just to allocate Grand Gulf costs, but to allocate the costs of all nuclear capacity on the MSU system. The judge also concluded that the costs of Grand Gulf Unit No. 2 should not be included in the automatic adjustment clause of the UPSA since completion of the unit and its costs are speculative, and the rationale for allocating costs of that unit may be different when the unit is completed.

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[4] Two other proposals, in addition to MSE's, were also before the judge. The Mississippi Public Service Commission had proposed that the Grand Gulf allocation be based on the 1973 System Agreement, with Grand Gulf deemed to be a participation unit. (The operation of the 1973 Agreement is discussed *infra*.) The City of New Orleans proposed allocating Grand Gulf power based on the present peak demands of the MSU operating companies.

Exceptions to the initial decision were filed by the following participants: the State of Arkansas, Arkansas Industries, AP&L, the Arkansas Public Service Commission (APSC), the Cities of Benton, North Little Rock, Osceola, and Prescott, Arkansas, and the Farmer's Electric Cooperative Corporation, the Congressional Delegations of Arkansas and Missouri, the Cities of Conway and West Memphis, Arkansas, International Paper Company, the Louisiana Public Service Commission (LPSC), the Mississippi Public Service Commission (MPSC) and Mississippi Attorney General, Mississippi Legal Services Coalition, the Missouri Public Service Commission, the City of New Orleans (CNO), Occidental Chemical Corporation, MSE, and the Commission Trial Staff.

Because the briefs are so numerous and many of the exceptions are repetitive or overlap, we will not enumerate the exceptions of every party. Rather, the following description categorizes the participants according to their general positions on exceptions regarding the Grand Gulf allocation issue. Also, because many of the exceptions in this docket overlap with those in ER82-483, they will be stated only briefly here and are described in greater detail in the discussion of ER82-483. Arguments made in briefs opposing exceptions in both dockets are not described separately because they generally repeat arguments previously made; where they do raise something new, they are discussed where appropriate in the opinion.

Mississippi Parties

The MPSC, Mississippi Attorney General, and Mississippi Legal Services Coalition claim that the judge's ruling is based on numerous erroneous factual and legal conclusions, and will have an unduly discriminatory impact on Mississippi ratepayers. They assert that the decision undermines the MPSC's determination pertaining to the need and economic justification for Grand Gulf when it granted a certificate to build the plant in its State. Lastly, they

claim that the decision violates the doctrine of equitable estoppel since the MPSC relied on representations, made in the State certificate proceedings, that excess Grand Gulf capacity would be sold to the other operating companies.

Arkansas Parties

The Arkansas participants, joined by the Missouri participants, are major objectors to the judge's Grand Gulf allocation. They claim that the Commission has no jurisdiction to compel MSE to sell or AP&L to purchase Grand Gulf power, particularly since MSE is not a jurisdictional utility and AP&L has no contractual responsibility to purchase power under the UPSA. The *Mobile-Sierra* doctrine,[5] they assert, precludes alteration of the voluntary UPSA absent unusual circumstances.

The APSC specifically contends that an order requiring AP&L to purchase Grand Gulf power from MSE would improperly intrude on its regulatory authority regarding retail rates and the necessity for plant construction. If the Commission does have the authority to compel AP&L to purchase power, the APSC claims that it is inappropriate to exercise such power here.

The Arkansas participant further argue that the judge erred in finding the filed UPSA to be unjust, unreasonable, and unduly discriminatory. A major error by the judge, they state was his analysis of the retail rate impact of various allocations, and his failure to analyze allocation from the standpoint of the *need* for Grand Gulf power. They also dispute the judge's findings that generation on the system has been planned to serve the system as an integrated entity, and that one of the system's goals was to equalize generating costs.

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[5] *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) (*Mobile*); and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) (*Sierra*).

Louisiana Parties

The Louisiana parties other than CNO do not object to the judge's Grand Gulf allocation. CNO excepts to the judge's failure to accept its proposal to allocate power and related costs among the four subsidiaries based on each company's current relative peak demand.

Middle South Energy, Inc.

MSE's exceptions to the initial decisions concern issues other than the specific Grand Gulf allocation percentages for the operating companies.

Commission Trial Staff

The Trial Staff's exceptions also are to issues other than the specific Grand Gulf allocation percentages for the operating companies.

B. Docket No. ER82-483 (System Agreement)

The System Agreement which is at issue in Docket No. ER82-483 sets forth the terms and conditions for transactions among the four MSU operating companies, including the sale and exchange of capacity and energy. Transactions among the companies have been controlled by some form of system agreement for over 30 years, with three similar agreements in all—the 1951, 1973, and 1982 versions. This docket involves the 1982 version filed by Middle South Services, Inc. (MSS), the service company subsidiary of MSU.

The system agreements have provided the contractual basis for planning and operating the companies' generating units on a single-system basis, and also have provided a basis for equalizing certain cost imbalances that result from this method of planning and operating the units. How the previous agreements have done so is as follows. If a company was responsible for 30% of the system's demand, it became responsible for 30% of the system's capacity. If the company's owned or purchased capacity was more than

30% of the system's capacity, the company was said to be "long" and received payments from the other companies for the difference. If the company's owned or purchased capacity was less than 30% of the system's capacity, it was said to be "short" and had to make payments to the others.

Under the 1973 System Agreement, payments from the short to the long companies were based on the costs of the long company's most recently installed generating unit. The 1982 System Agreement, as filed, would change the basis on which payments are made by the short to the long companies. Rather, than basing payments on the capacity costs of the long companies' most recent generating units (nuclear and coal-fired units), it would instead base them on the capacity costs of the long companies' intermediate units (oil and gas-fired units). This change constitutes the major dispute in the case. The change supposedly was made on the basis that, due to their fuel costs, the older units now have operating characteristics directly related to use as "reserve" capability, and it is only reserve capacity that is to be equalized under the System Agreement.

Four other allocation methodologies were proposed in this docket but, because several of them are similar, there are actually only a total of three basic proposals before the Commission:

(1) MSS's proposal, above, to equalize reserve capacity costs only, based on the cost of the long companies' older oil and gas-fired generation units;

(2) the Mississippi Public Service Commission's (MPSC) proposal to equalize reserve capacity costs only, based on the cost of the long companies' most recent generation units, and to make MSE a party to the System Agreement; and

(3) proposals by the Commission Trial Staff, the LPSC, and CNO to equalize all or part of the system's production costs.[6]

MSS's proposal was supported by AP&L, the Arkansas Public Service Commission, and other Arkansas parties, as well as the Missouri Public Service Commission and Missouri Public Counsel. The production cost equalization proposals would have substantial impact on the ratepayers represented by these parties. According to Staff's initial brief, AP&L would pay *$163 million more* in 1984 under the LPSC proposal than under the MSS proposal, and *$228 million more* under the Staff proposal than under the MSS proposal (excluding consideration of Grand Gulf or any decrease in AP&L's projected coal transportation expenses).

As for the MPSC proposal, it would have the effect of making the Grand Gulf units participation units, since they are the only units owned by MSE. Grand Gulf's capacity costs, which carry energy entitlements, would thus shift among the individual companies as the companies become short or long, and the short companies would end up paying for Grand Gulf's capacity and energy costs. Because MP&L is a long company and is expected to remain so until the 1990's, it would avoid any responsibility for Grand Gulf during that time.

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[6] Three variations of production cost equalization were presented: (1) the Commission Trial Staff proposed to equalize the costs of all base load (coal and nuclear-fired) facilities on the basis of each company's annual average load to the average annual load of the system, and to levelize all carrying charges for the base load units; (2) the LPSC proposed to combine all production costs (not just base load), and allocate them based on each company's capability responsibility; and (3) CNO proposed to equalize all base load units, but also to allocate the remaining production units, including peaking units, on a two-part basis by which capacity costs would be treated as set out in MSS-1 of the 1982 System Agreement and energy would be drawn from the system pool.

The Initial Decision

Presiding Judge Head thoroughly analyzed and discussed the Middle South System, as well as the arguments for and against production cost equalization. His major findings and conclusions are as follows.

(1) While this Commission has the power, from a jurisdictional standpoint, to order production cost equalization, such power must be exercised with caution since it will have a substantial impact on the retail ratemaking ability of the States involved. (For example, approval of the Staff proposal would subject more than 75% of rate base to our jurisdiction, and an even greater percentage of the operation and maintenance expenses, thus leaving the States with little control over the absolute level of retail rates.) The case law concerning State/Federal jurisdictional disputes and the legislative history of the Federal Power Act support a finding that Federal regulation is meant to be supplemental to, not in place of, State regulation. Therefore, this Commission's exercise of overlapping jurisdiction must be tempered and weighed against the policy consideration that generation facilities and retail rate regulation should be left to the State commissions.

(2) The policy to encourage voluntary pooling, contained in the Federal Power Act (FPA) and Public Utility Regulatory Policies Act (PURPA), cannot operate to block the Commission's power under Section 206(a) of the FPA to reallocate costs and expand the scope of power pooling transactions, if to do so is necessary in the public interest.

(3) Although adoption of any one of the various production cost allocation proposals would result in substantial savings to various companies, none of the cost differentials or impacts are of such magnitude that they *per se* require adoption of one proposal over another. These impacts are a factor to be taken into account in determining a just and reasonable system arrangement.

(4) Characterizations by this agency and others that the Middle South System is a closely integrated and coordinated power pool do not specifically dictate that production cost equalization must be ordered.

(5) The MPSC's proposal (retention of the 1973 System Agreement) is not just and reasonable. It would result in the short companies (LP&L and NOPSI) paying approximately $3 billion for the Grand Gulf costs for a 10-year period, after which time MP&L would become short and then enjoy its share of the unit in the less expensive years (after it has been initially depreciated). The proposal also would not tend to achieve the System Agreement's stated goal of each of the operating companies diversifying its fuel mix.

(6) The record establishes that the Middle South companies constitute a highly integrated electric system, with common planning and central dispatch, for the purpose of achieving economies of scale and enhanced reliability. However, the evidence also reveals a pattern of autonomy, particularly as to specific plant site locations, fuel, and financing. The MSU companies have never been operated as a single system where all the generation is shared and responsibility therefor is allocated to the operating companies. To revise the 1982 System Agreement by ordering production cost pooling and equalization would constitute a drastic deviation from past system practices relating to intercompany transactions, and would change the underlying nature of such operations. It would amount to a revision of the Middle South System in a manner not consistent with the history of operation on the system, which reveals a pattern of autonomy on the part of the individual operating companies, and indicates that generation additions other than Grand Gulf were made primarily to satisfy individual company needs. Production cost equalization is not warranted at this time. The 1982 System Agreement should be approved with regard to its reserve equalization provisions.

(7) Grand Gulf, however, is an anomaly to the regular planning and construction of generating facilities on the system and, unlike other units, it *was* planned, licensed, and constructed as a *system* plant, by a separately created entity, and was intended to supply power not only in Mississippi, but throughout the entire MSU system. As such, the financial responsibility for Grand Gulf should be borne by all the operating companies. Grand Gulf should be integrated into the 1982 System Agreement by having each of the four operating companies pay for the production costs of that facility based on the ratio that the individual operating company's total annual demand bears to the total system annual demand. This ratio would be calculated at the close of the calendar year.

To integrate Grand Gulf responsibility into the 1982 System Agreement, the judge concluded that each operating company's share of the unit could be treated as part of its capability under Section 2.14 of Article II, as an input in MW available under contract from a supplying source. As such, it would affect each company's capability and become part of the reserve equalization calculation. Thus, the Grand Gulf share would be taken into account in determining which company is long or short.

The judge stated that although a precise calculation had not been made, his proposed treatment of Grand Gulf should result in economic differences at about the midpoint of those shown for the 1982 System Agreement and the equalization proposals. The net effect is that Grand Gulf would be equalized but LP&L's Waterford 3 nuclear unit would not. (According to a March 18, 1985, article in *The Wall Street Journal,* Waterford 3 was to be in commercial operation during the second quarter of 1985.)

On February 8, 1985, MSS filed a motion requesting clarification of the initial decision, seeking a definition of the terms "individual operating company's total annual demand" and "total system demand." On March 6, 1985,

the judge issued an order denying the motion for clarification, but stating that the APSC's interpretation of the unclear terms was correct. The APSC, in its response to the motion for clarification, had suggested that the terms refer to the total annual kilowatt-hours used by an operating company (individual operating company's total annual demand) and the total annual kilowatthours used by the Middle South system as a whole (total annual system demand), with off-system sales excluded from both terms.

Exceptions to the initial decision were filed by the following participants: MSS, MP&L, AP&L, LP&L and NOPSI, the Mississippi Public Service Commission and Mississippi Attorney General, the Louisiana Attorney General, the Governor of Louisiana and Louisiana Department of Natural Resources, the Louisiana Public Service Commission, Union Carbide Corporation, Occidental Chemical Corporation and Georgia Gulf Corporation, the City of New Orleans, Jefferson Parish, Louisiana, the Arkansas Public Service Commission joined by the Missouri Public Service Commission and Missouri Public Counsel, the Arkansas and Missouri Congressional Delegations, AMAX, Inc., International Paper Company, Arkansas Industries, the Arkansas Attorney General, and the Commission Trial Staff.

As was done with the ER82-616 exceptions, the following description categorizes the participants according to their general positions on exceptions.

Mississippi Parties

The MPSC and Mississippi Attorney General (MAG) claim that the judge's decision is outside the scope of the Federal Power Act and ignores the dual regulation of electric utilities by State and Federal government. The MPSC granted a certificate to MP&L to construct Grand Gulf in reliance on representations that the Grand Gulf units would become participation units under the System Agreement, and that none of the additional capacity costs of the units would be allocated to MP&L in excess of its area demand

requirements. Citing recent Supreme Court authority for the proposition that the States retain traditional authority over decisions as to the need and economic feasibility of additional generating capacity,[7] the MPSC and Attorney General contend that the initial decision undermines such State authority. They further argue that it violates the doctrine of equitable estoppel, since the MPSC detrimentally relied on the representations of MP&L and MSE, as agents for the MSU system, concerning allocation of Grand Gulf costs.

The MPSC and MAG further contend that the initial decision will have a chilling effect on future multi-state cooperation in constructing additional generating capacity for future needs. They pose the question of why a reasonable State commission would grant a company's request to build additional capacity if that commission had no assurances as to the disposition of costs associated with capacity beyond what is needed to serve the requesting company's customers.

MP&L is currently a long company. The MPSC and MAG argue that the 1982 System Agreement would require MP&L to subsidize capacity-deficient operating companies because it would require MP&L to take and pay for the high costs of Grand Gulf, yet sell its excess generation based on the low cost of its oil and gas units.

The MPSC and MAG continue to advocate the participation unit concept as being in harmony with the legal policy that the States retain authority regarding the need for and economic feasibility of additional capacity, and in harmony with the history of the MSU system operation which has encouraged State approval of generating capacity on the system.

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[7] *Pacific Gas and Electric Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 90 (1983).

Other Mississippi parties are not aligned with the MPSC and MAG. The Mississippi Congressional Representatives, MP&L, and Mississippi Industries support the ER82-483 initial decision. If that initial decision is not adopted, however, they support production cost equalization. MP&L previously supported system-wide production cost equalization, but in its brief on exceptions states that it has now concluded that the initial decision in ER82-483 more accurately reflects the history and operation of the MSU system than does the initial decision in ER82-616, and that it reaches a just and reasonable result.

Arkansas Parties

Because so many exceptions and arguments are raised by the various Arkansas interests, the major ones are enumerated individually below:

(1) The judge in this proceeding had no authority to allocate Grand Gulf costs. The scope of this docket was specifically limited to the System Agreement. MSE is not a party to the System Agreement and was not a party in this docket. The Grand Gulf allocation issue is solely within the scope of ER82-616, and consolidation of the two dockets was previously denied.

(2) The Commission has no jurisdiction under the FPA to require AP&L to purchase or MSE to sell Grand Gulf power. Although the judge and some parties use the term "allocation," the judge's decision in effect constitutes a forced purchase and sale, since it would require MSE to sell and AP&L to buy 33% of Grand Gulf, and AP&L to sell an equivalent amount of its own coal and nuclear power. To compel AP&L to purchase capacity and enlarge its generating capability violates Sections 201(b), 202(b), and 212(a) of the FPA.

(3) Grand Gulf was not, as the judge held, planned for system use. The record shows that it was built only for those companies anticipating a deficiency in coal and nu-

clear capacity. AP&L was not one of those companies. Further, the system never had a goal to equalize costs.

(4) The judge improperly found that the Commission has jurisdiction to order production cost equalization. The *Mobile-Sierra* doctrine precludes overturning the voluntary 1982 System Agreement unless there is an uneqivocal public necessity to do so. Although the Commission may have authority to *modify* the transactions and rates proposed under the System Agreement, it cannot substitute dramatically different transactions since the statutory scheme provides for regulation of *voluntary* transactions. Jurisdiction is given under Section 201 of the FPA, and Section 206 cannot be used to overstep this jurisdiction authority.

(5) Equalization of Grand Gulf or other production costs would result in unauthorized Federal regulation of rate base and of generating facilities. Requiring AP&L to buy Grand Gulf or other capacity would change the retail rate base because it results in a transfer of rate base from other utilities to AP&L. It would also shift generation from one utility to another. The States would be required to allow pass-through of these costs in retail rates, thereby being forced to relinquish a critical aspect of State regulation, i.e., determination of what fixed and operating costs of generating facilities should be allowed. Under production cost equalization, a State commission would be forced to approve charges that derive from plants which it did not approve, which are outside its jurisdiction, and which were not needed to meet the needs of the State's ratepayers.

(6) Equalization of costs would conflict with representations to the APSC during certification proceedings that AP&L's plants were necessary to meet AP&L peak load within its own system, and that plants would be maintained and operated by AP&L to meet native load requirements.

(7) The judge's findings regarding production cost equalization could frustrate Section 202 of the FPA, and Section 206(b) of the PURPA, under which the Commission is to encourage voluntary power pooling and coordination.

(8) Assuming that the Commission has jurisdiction to reallocate Grand Gulf costs, the judge erroneously failed to consider and credit the operating companies for their existing capacity. For example, a substantial amount of AP&L's current base load energy is going to benefit the pool since AP&L will have excess capacity into the 1990's, even absent Grand Gulf. If AP&L were allocated Grand Gulf capacity, it would be unable to use any of the Grand Gulf energy and the forced Grand Gulf purchase would also go to benefit the pool. In other words, AP&L would be forced to buy capacity it can't use. Any allocation must consider need as well as current demand.

(9) Production cost equalization in this case would have nationwide implications and would inhibit power pooling. MSU pooling practices are typical of numerous pools in the country, and none of the other pools have ever have ever equalized total capacity costs. Facilities with low operating and construction costs would attempt to withdraw from existing pools or refrain from entering new ones. Pool members would be uncertain as to future cost stability and unable to plan accurately for load growth, sales, and capacity construction. It could also impair a pool member's ability to raise capital. A utility forced to purchase additional capacity might not be able to recover the additional costs through increased rates right away because of regulatory lag, and this could have an adverse financial impact on the company.

(10) Production cost equalization would inhibit the States in granting power plant certificates. They would be unable to balance the need for the plant in a particular State because it would never be used solely for native load.

(11) Production cost equalization would undermine the goals of the System Agreement, particularly Section 3.05, which says that a long-term goal is for each company to have a proportionate share, not a proportionate sharing, of base load units to meet native load.

(12) Production cost equalization would conflict with the Public Utility Holding Company Act (PUHCA). It would undermine the SEC's authority because it would ignore the separate identities of the operating companies. The main purpose of the PUHCA was to reduce the size and simplify the structure of affiliated utility systems so that they could be regulated by local authorities. Production cost equalization would frustrate this.

(13) If the 1982 System Agreement is found unjust, unreasonable, unduly discriminatory, and unequivocally against the public interest, then the burden is on those opposing the 1973 System Agreement to show that it should not be reinstated.

The Arkansas interests continue to support the 1982 System Agreement as filed, claiming that it meets the system goals of moving each company toward a proportionate ownership of coal and nuclear capacity, and reducing each utility's fuel costs. The APSC, however, states that if the 1982 Agreement is rejected, the Commission should reinstate the 1973 System Agreement but amend it to state that units owned by MSE but sold to individual operating companies may qualify as participation units for determining a company's capability.

Arkansas Industries also suggests that if the 1982 System Agreement is not accepted as filed, there are several options available other than production cost equalization. These include retention of the 1973 Agreement, with Grand Gulf treated as a participation unit and a levelization of the high front-end costs as to LP&L and NOPSI, or requiring joint ownership of Grand Gulf by looking through MSE and assigning the plant to the rate bases of the

companies as though the plant were jointly owned. Noting that the January 5, 1985 proposed settlement in these dockets recognizing the shareholders' responsibility to absorb some of the costs of a new, extraordinary expensive plant that no one wanted, International Paper contends that if the Commission does allocate MSE capacity through the System Agreement, then it must allocate a substantial portion to the Middle South shareholders.

Louisiana Parties

The Louisiana participants all support some form of cost equalization, but vary somewhat in their exceptions and in what they are willing to accept. Their major exceptions follow, with major areas of disagreement specifically noted.

(1) The initial decision will result in LP&L bearing 100% of the expensive Waterford 3 costs, and 41% of Grand Gulf costs. The costs of these two units together will equal more than the total net plant investment in the entire system in 1981, and the effect of the decision is undue discrimination against LP&L.

(2) The testimony and documentary evidence show that *all* generation additions on the MSU system have been planned and operated on a systemwide basis, and that there is no distinction between Grand Gulf 1 and Waterford 3. The judge's finding of autonomy is not supported by the record and conflicts with his earlier findings regarding the integrated nature of the system. The evidence shows that all critical decisions regarding plant additions are made by and for the system as a whole.

(3) Some form of production cost equalization is necessary to avoid undue discrimination on the system. This is because the filed System Agreement creates enormous cost disparities that are based only on accidents of timing in decisions as to the building of plants for the entire system.

(4) Production cost equalization would not result in an undue extension of Commission jurisdiction. The judge misunderstood its impact. His finding that 75% of AP&L's rate base would be moved from State to Federal control is incorrect and ignores the fact that even in the absence of production cost equalization, the Commission would be required to exercise jurisdiction over a substantial portion of these costs. Also, the judge's analysis is flawed in that the issue here is discrimination in rates at the *wholesale* level, yet he relied on evidence as to revenue per kWh at the *retail* level and failed to recognize legitimate cost-based differences at the retail level.

(5) Production cost equalization would not be a dramatic departure from past system operation, as found by the judge. The overall pattern of generation additions shows that capacity was added to benefit the system as a whole, and that previous system agreements achieved an approximate equalization of production costs. Additionally, equalization would achieve the basic objective of the System Agreement to equalize any imbalance of costs of facilities used for the mutual benefit of the companies.

(6) The judge erred in making any allocation of Grand Gulf in this docket, since the issue was reserved for ER82-616 and consolidation of the two dockets was denied.

(7) The judge was obligated to respond to allegations that the 1982 System Agreement is not just and reasonable, and failed to do so.

(8) The judge ignored the proposal of LP&L, NOPSI, and MP&L to consider a phasing-in of production cost equalization over a three-year period. This would avoid the need for future *ad hoc* adjustments based on changed circumstances, and would permanently solve the problems presented in this case.

Some of the Louisiana parties assert the following alternative positions if production cost equalization is not adopted:

(1) The LPSC and Attorney General of Louisiana state that if production cost equalization is not adopted, then the initial decision should be overturned as to Grand Gulf and the ER82-616 allocation adopted, but using updated cost estimates for Grand Gulf 1 and Waterford 3. If the judge's separate allocation for Grand Gulf is upheld, the remedy should be the same for Waterford 3.

(2) Occidental Chemical Corporation and Georgia Gulf corporation state that if production cost equalization is not adopted, then they support either: (1) adoption of the 1982 System Agreement but with the ER82-616 Grand Gulf allocation, updated to reflect the current cost estimates for Grand Gulf 1 and Waterford 3 or (2) another fixed responsibility allocation (as opposed to the ER82-483 shifting allocation) for both Grand Gulf 1 and Waterford 3, in proportion to the companies' most recent responsibility ratios.

(3) The City of New Orleans supports any of the three production cost equalization proposals if applied to all generating units. If none of those is adopted, however, it supports the Grand Gulf equalization in ER82-483 but excepts to the approval of the 1982 System Agreement. If full production cost equalization *is* ordered, CNO asserts that it should cover *all* production plants, not just Grand Gulf and Waterford 3, because to do otherwise would deny NOPSI access to any coal-fired generation.

Middle South Services, Inc.

MSS's major objection to the judge's decision is the finding that cost responsibility for Grand Gulf should be revised annually. Contrary to the judge's belief, states MSS, there are no foreseeable shifts in demand patterns among the companies. Therefore, Grand Gulf cost allocation should be permanent. MSS claims that an annual revision of cost responsibility would render rates less stable, and that a permanent allocation would facilitate long-term

plans for construction and retirement of capacity by each company.

Commission Trial Staff

The Commission Trail Staff position is aligned with that of the Louisiana parties. Staff excepts to the judge's refusal to order production cost equalization and claims that the judge's finding as to the pattern of autonomy on the system is unsupported by the record. The judge, states Staff, relied only on limited testimony in making this finding, and ignored other evidence regarding the lack of autonomy on the system as well as evidence of AP&L's historical dependence on the system. Staff also objects to the judge's conclusion that production cost equalization would result in a substantial departure from past practice.

Staff further excepts to the judge's conclusion at pp. 65,149 and 65,170 that cost equalization would divest the States of their control over rate base. Staff points out that transmission costs are already equalized without any suggestion that this affects ownership, control, or State jurisdiction. Additionally, Staff disputes any finding that equalization would alter representations made to State commissions. In support, Staff states that the APSC historically relied on the operation of the system as a whole, and notes that the judge already rejected the MPSC's detrimental reliance argument.

Staff claims that there is no record basis for the judge's finding that Grand Gulf is any different from other system units, or for his Grand Gulf allocation. As for the 1982 System Agreement, Staff contends that it fails to meet its own objective of equalizing any imbalance of costs on the system and is itself a substantial departure from the historic operation of the system which produced a rough equalization of costs among the companies. Staff supports production cost equalization as the record-supported method of achieving the objectives of the system as expressed in the System Agreements over the past 30 years.

C. Commission Jurisdiction

Several jurisdictional challenges have been made in both dockets regarding this Commission's authority to amend the UPSA and the System Agreement. There are three major arguments: (1) Grand Gulf is a *generating* facility and thus is not under our jurisdiction under Section 201(b) of the Federal Power Act; (2) the Commission has no jurisdiction to force a purchase or sale of power, and thus cannot allocate any Grand Gulf costs to AP&L; and (3) the *Mobile-Sierra* doctrine precludes modification of the UPSA or 1982 System Agreement. We affirm the rejection of these arguments by Judges Liebman and Head (26 FERC at pp. 65,113-18; 30 FERC at pp. 65,146-47, 65,140-51, and 65,154), and find it necessary to add only briefly to their discussions.

First, we wish to address a recent Supreme Court case, *Arkansas Electric Cooperative Corp. v. Arkansas Public Service Commission*, 461 U.S. 375 (1983), cited by the APSC, Arkansas Industries, the MPSC and MAG, and AMAX as supporting broader State jurisdiction over electric rates. In that case the Court upheld the APSC's assertion of jurisdiction over a rural electric power cooperative under the supervision of the Rural Electrification Administration (REA). However, that case was quite different from the present one since it involved jurisdiction over rural electric cooperatives, which the Commission's predecessor (and a court of appeals) had determined were *not* jurisdictional under the Federal Power Act.[8] Finding no Federal preemption of State regulation of rural electric cooperatives under the Federal Power Act or otherwise, the Court next looked to whether the Commerce Clause

[8] The Court noted that if the Commission or courts were to ever determine that the Commission *did* have jurisdiction under the FPA over rural electric cooperatives, "we would obviously be faced with a very different preemption question." 461 U.S. at 383, note 7.

limited State regulation and applied a balance-of-interests test in making its determination.

In the present case, there is clear Federal preemption since the sales for resale in interstate commerce among the Middle South pool members are now and have been subject to this Commission's and its predecessor's jurisdiction under the Federal Power Act. The Court in *Arkansas Electric, supra,* rejected the "bright line" distinction between wholesale and retail rates under the Commerce Clause, which had been enunciated in *Public Utilities Commission of Rhode Island v. Attleboro,* 273 U.S. 83 (1927). However, the Court emphasized that the "bright line" drawn by the Congress was still intact under the Supremacy Clause:

> *Southern California Edison Co.* and other cases have made it clear that the Federal Power Act draws a bright line between the respective jurisdictions of federal and state regulatory agencies. 461 U.S. at 392-3.

Where, as here, the Federal Power Act clearly provides for preemptive Commission jurisdiction over wholesale electric rates in interstate commerce, the Commerce Clause question and the balance-of-interests test[9] under it are never reached.[10]

Next, in response to the argument that any change in Grand Gulf entitlements would constitute a forced pur-

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[9] We read Judge Head's decision in Docket No. ER82-483, 30 FERC at pp. 65,150-51, as completely consistent with this view on the jurisdictional question. His discussion of the need to balance Federal and State interests relates to policy concerns regarding the impact of Commission orders on retail rates, rather than to legal, jurisdictional concerns.

[10] In any event, it would be hard to imagine how, under a balance-of-interests test, one could characterize a multi-state pool agreement as a matter of primarily "local interest" with "only incidental" effects on interstate commerce.

chase or sale, we find that the issue here is not whether a company should be forced to purchase or sell power, but rather is the appropriate allocation of costs among integrated companies owned by the same parent. In other words, the real issue is whether rates among those companies are just, reasonable, and not unduly discriminatory.

The Commission followed a similar line of reasoning in *Nantahala Power Co.,* Opinion Nos. 139 and 139-A, 19 FERC ¶61,152 (1982) and 20 FERC ¶61,430 (1982). In *Nantahala,* the Commission re-allocated energy entitlements between subsidiaries of an industrial company (Alcoa), in order to achieve just and reasonable rates. The two subsidiaries, Nantahala and Tapoco, had allocated certain TVA entitlements between themselves pursuant to a 1971 Apportionment Agreement which revised the entitlements allocation under an earlier agreement. The Commission was careful to state that it was not reforming the 1971 Agreement and was not concerned with the mechanics of how entitlements were allocated; rather, it was setting *rates* as though Nantahala was receiving a fair share of entitlements. In upholding the Commission's decision, the Fourth Circuit stated that the Commission's burden in such a situation is not only to scrutinize rates, but also the fairness of all transactions allocating resources between subsidiaries. *Nantahala Power & Light Co. v. F.E.R.C., 727* F.2d 1342, 1348 (4th Cir. 1984). Although *Nantahala* is not directly on point, we believe that it provides support for the Commission's authority to set rates as though a different allocation existed.

Another matter related to the forced purchase/sale argument concerns AP&L's involvement in Grand Gulf. While the forced purchase/sale argument applies to all of the UPSA signatories, arguably it has more force in regard to AP&L since under the UPSA, AP&L has not agreed to buy *any* Grand Gulf capacity. However, we reject any assertion or implication by any of the parties that AP&L has had no involvement in the Grand Gulf unit, or that

the unit was planned only for the other operating companies. As detailed in Judge Liebman's decision, 26 FERC at pp. 65,102-03, AP&L has been continuously involved in the system decisions regarding Grand Gulf and MSE. Of particular relevance is the fact that AP&L remains financially obligated to creditors for 17.1 percent of Grand Gulf project costs should the other operating companies not meet their obligations. (ER82-616, Ex. 1, pp. 7-15; Ex. 83; Tr. 353-8). We therefore find that AP&L cannot divorce itself from this case simply because the UPSA, as filed, allocates no Grand Gulf entitlements to it.

Lastly, concerning the jurisdictional argument that the *Mobile-Sierra* doctrine precludes the Commission from modifying the *voluntary* UPSA or 1982 System Agreement, we affirm and adopt the judges' rejections of this argument. (26 FERC at pp. 65,114-15 and 30 FERC at pp. 65,146-47.)

D. Federal/State Relationship

Several Arkansas parties argue that production cost equalization would impinge on State regulatory jurisdiction. Most of these arguments are appropriately considered by Judge Head, 30 FERC at pp. 65,148-51, and we find no need to add to his discussion except for the matters discussed below.

Several parties rely on the Supreme Court's recent recognition that "the States retain their traditional responsibility in the field of regulating electric utilities for determining questions of need, reliability, cost, and other related state concerns." *Pacific Gas and Electric Co. v. State Energy Resources Conservation and Development Comm'n,* 461 U.S. 190, 205 (1983). However, they ignore the fact that the Court also expressly recognized this Commission's authority as an exception to that of the States:

> With the exception of the broad authority of the . . . Federal Energy Regulatory Commission, over the need

> for and pricing of electrical power transmitted in interstate commerce, . . . these economic aspects of electrical generation have been regulated for many years and in great detail by the states. 350 U.S. at 205-206.

Thus, we reject any argument that the Commission's authority over interstate sales was found subordinate to State jurisdiction in the *Pacific Gas* case.

In reference to the claim that production cost equalization would violate the doctrine of equitable estoppel insofar as the State commissions relied on certain representations made in State certification proceedings as to how costs would be allocated or how generating units would be used, Judge Head properly disposed of this issue in finding that a State commission could not reasonably rely on representations in State proceedings as guarantees against modification of the System Agreement since this Commission alone has jurisdiction over the Agreement. (30 FERC at p. 65,166.) Furthermore, the doctrine cannot operate to bind this commission since we made no representations in and were not a party to any of the State certification proceedings.

E. Conflict with PURPA, PUHCA, or FPA

Some parties have argued that production cost equalization would conflict with the Public Utility Regulatory Policies Act (PURPA), 16 U.S.C. §824a-1(b) (Supp. V. 1981), the Public Utility Holding Company Act (PUHCA), 15 U.S.C. §79, *et seq.*, and Section 202(a) of the Federal Power Act (FPA), 16 U.S.C. §824a-1. They contend that Section 202(a) of the FPA and Section 206(b) of PURPA are intended to encourage *voluntary* coordination and pooling arrangements among electric utilities, and that production cost equalization would have a chilling effect on coordination and conflict with this policy. It is also argued that production cost equalization would conflict with the SEC's jurisdiction over regulated public utility holding

companies under PUHCA, since a principal purpose of PUHCA is to prevent manipulation of an operating utility owned by a holding company to the detriment of the customers of the operating utility.

Judge Head adequately rejected these arguments in his decision, 30 FERC at pp. 65,151-54, and we affirm and adopt his discussion.

F. Integrated Nature of the MSU System

Both Judge Liebman in Docket No. ER82-616 and Judge Head in Docket No. ER82-483 concluded that the records in their respective dockets supported a finding that the MSU system is integrated. (26 FERC at p. 65,106; 30 FERC at p. 65,167.) Judge Head, however, diverged from the reasoning of Judge Liebman by concluding that although the Middle South companies constitute a highly integrated electric system, the evidence also reveals a "pattern of autonomy," particularly as to decisions regarding specific plant site locations, fuel, and financing of new units. (30 FERC at p. 65,168.) He further determined that Grand Gulf was an "anomaly" to the regular planning and construction of units on the MSU system and, unlike other units, was intended to serve not just MP&L but rather the entire MSU system. (30 FERC at pp. 65,170-72.)

Having reviewed the evidence in both dockets, we affirm and adopt the findings of both judges that the Middle South companies constitute a highly coordinated integrated electric system. We conclude that this coordination and integration results in planning, construction, and operations which are conducted primarily for the system as a whole. We reject Judge Head's separate findings that there is a "pattern of autonomy" on the system and that Grand Gulf is an "anomaly" to the regular planning and construction of system units.

The operation of the Middle System and the common officers and directors among MSU and its subsidiaries are described in detail by Judge Head at 30 FERC at pp. 63,141-43. Because of the overlapping officers and directors, and particularly because the System Operating Committee consists of representatives from each of the four operating companies and MSS, it is clear that there is input from the individual companies and consideration of their needs in making coordinated decisions. However, the evidence also is clear that major critical decisions, including decisions to build new generating units, are made by the Operating Committee for the benefit of the system as a whole. Our findings are discussed below. First, we review some basic pertinent provisions of the coordination agreements, followed by an analysis of the record evidence.

Section 3.01 of the "Objectives" sections of the 1973 and 1982 System Agreements[11] describes the basic purpose of the coordination among the companies. This section is almost identical in wording in the 1973 and 1982 versions. The 1982 version reads:

> 3.01 The purpose of this Agreement is to provide the contractual basis for the continued planning, construction, and operation of the electric generation, transmission and other facilities of the Companies in such a manner as to achieve economies consistent with the highest practicable reliability of service, subject to financial considerations, reasonable utilization of natural resources and minimization of the effect on the environment. This Agreement also provides a basis for equalizing among the Companies any imbalance of costs associated with the construction, ownership and operation of such facilities as are used for the mutual benefit of all the Companies.

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[11] MSS Ex. 2 (1982 System Agreement); APSC Ex. 25 (1973 System Agreement).

Section 3.02 of the 1973 Agreement recognizes that economies of scale require planning, construction, and operation of bulk power supply "on the basis of a single system," and that this will dictate installation of generating units of the larger ratings available at that time, in generating stations of large size, strategically located with regard to fuel and water supply. The same section in the 1982 Agreement is shortened. It recognizes that economies of scale and integrated operations require that planning, construction, and operation of bulk power supply be "on a coordinated basis."

The System Operating Committee is the organization which historically has administered the provisions of the System Agreements among the four operating companies.[12] As stated above, it consists of representatives from each of the operating companies and MSS. Section 2.06 of the 1973 and 1982 Agreements provides that each company is to periodically furnish estimates of peak load and capability to the Operating Committee, and the Committee is to then determine a generation addition plan to provide capacity for the projected system load. Section 4.01 of the 1973 System Agreement requires that each company to whom the Committee "assigns" a generating unit for installation make the necessary financial arrangements and promptly proceed with the design and construction of the unit to meet the agreed upon "in service" date in the system plan. The 1982 System Agreement has the same requirement in Section 4.01, but does not use the word "assigns." Section 5.04 of the 1973 System Agreement provides that all decisions of the Operating Committee be by a two-thirds majority vote. Section 5.04 of the 1982 System Agreement changes this to a simple majority vote.

Several witnesses in the two dockets testified as to the nature of coordinated operations and the role of the Sys-

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[12] *Id.;* APSC Ex. 3 (1951 System Agreement memorandum).

tem Operating Committee in decisions to build additional generating capacity on the MSU System. Mr. Lupberger, an officer of MSU, MSE, and MSS, testified in Docket No. ER82-616. He stated that the Middle South System basically "is operated as though it were one electrical system under one ownership, and in all candor, probably could not be separated or pulled apart without detrimental effects to the customer economically." (Tr. 347.)

When asked who makes decisions on whether to build a new generating facility on the system, Mr. Lupberger stated that the decision to build in essence is a system decision, requiring concurrence of the system as a whole, with the decision to be based on the ultimate costs and perceived needs of the system as a whole for electricity, and the expected need for power of the company proposing to build the plant. (Tr. 348-49.) Mr. Lupberger noted that the individual companies make recommendations to the Operating Committee which, in turn, makes recommendations to the management of all the companies concerning the appropriate generation addition plan. (Tr. 395-96.) In his view, new units are not "assigned" or "dictated" by the Operating Committee, but rather are determined by the Committee's concurrence with the recommendations of the operating companies. (Tr. 397.)

Mr. Stampley, a senior vice president for MP&L and former System Operating Committee member, also testified in ER82-616, and generally agreed with Mr. Lupberger's description. He stated that over the last 10 to 15 years, the Operating Committee has been at the center of coming up with system recommendations, acting as a coordination point among the chief executive officers of the individual companies. According to Mr. Stampley, the Operating Committee makes recommendations as a committee, and the individual Committee members inform their chief executive officers that the recommendations come from the Committee as a group. These recommendations

involve the general location, size, and type of plant to be built. (Tr. 739-42.)

Mr. Stampley further testified that past generation additions have been planned to serve the needs of the system and the companies that make up the system, with consideration given to such factors as locational economies, achieving economies of scale, and achieving the most desirable proportion of reserves on the system. (Tr. 780-81.) According to Mr. Stampley, the Operating Committee was created to allow joint planning which in turn would allow the best service to the combined loads of all the companies and allow the best service to the public. (Tr. 782.) He stated that the decision that a particular company will be responsible for building a new unit is the result of a coordinated effort, and thus new units are "assigned" to be built only in the broadest sense. (Tr. 783-84.)

A third witness who testified in ER82-616, as well as in ER82-483, is Mr. Trumps, the director of the System Planning and Forecasting Department at MSS. Mr. Trumps agreed in ER82-616 that in the past generation planning has been done on a systemwide basis, but with due consideration of the needs of the individual companies as to the location of new facilities. (Tr. 911.) He testified that the Operating Committee is responsible for developing generation addition plans from an engineering and operating standpoint, including recommendations as to the proper timing, location and types of units. (Tr. 912.) The Committee, he stated, was created to achieve the System's goal of achieving the best service to the system, the individual companies, and the public. (Tr. 914-916.)

In ER82-483, Mr. Trumps testified that a function of the Operating Committee is to make general decisions as to the size, location, and timing of units. The specifics as to size and location, he stated, are a function of the individual companies. (Tr. 2505-10.) He described the coordination process as one in which the individual companies

participate in the development of the Operating Committee's consolidated power plans. These plans are submitted to and approved by the chief executive officers of the operating companies, and the boards of directors of the individual companies approve their own construction projects and expenditures. (MSS Ex. 17 at 6-8.) Mr. Trumps testified that the MSU System has for at least the past 30 years planned, sited, constructed, financed, and operated production plant to minimize the system costs. However, in his view the decisions made were not totally from a system viewpoint since the individual companies also did studies as to what kinds of units were most appropriate for them. (Tr. 2693.)

Another witness in ER82-483 was Mr. Phillips, a senior vice president of AP&L, who testified that the Middle South companies in the past have agreed: to coordinate planning, construction, and operation of bulk power supply facilities on the basis of a single system; to size generating stations to achieve economies of scale; to strategically locate generation with regard to water and fuel supply; to plan generation to produce the lowest total cost on a system basis, consistent with reliability; to coordinate the plans of the individual companies so as to develop generation additions on a system basis, such that the companies' combined loads can be served with less aggregate installed capacity; and to share in the benefits and pay a share of the costs of coordinated operations. (Tr. 1000-04.)

Mr. Copeland, a former staff member of the APSC, the Arkansas Attorney General's Office, and the Arkansas Department of Energy, testified in ER82-483 as follows:

> Certainly, the system, overall, seeks to construct plants in the most economical fashion possible to benefit the total needs of the system. The system is not in the process or in the business to install excess capacity, systemwide, to make off-system sales. The ultimate objective of the operating committee is to

> make sure that on a systemwide basis, the planning is optimal for the system. And that does not mean, however, that individual plants within the system might not be built and designed for the individual operating companies, as long as that is not disadvantageous to the system as a whole. (Tr. 6729.)

The record in ER82-483 further includes testimony by Mr. Leo, Vice President of Economic Research at MSS, given in another pending Middle South case in Docket Nos. ER81-428 and EL81-12. Mr. Leo was a member and chairman of the committee that drafted the System Agreement. He stated that,

> [t]he units [capacity additions] are installed, under past practice, in response to the projected combined load forecasts of the individual companies. Therefore, the units are sized for the system need rather than for the needs of the company installing the units. Therefore, there are generally companies that have more capacity available than their responsibility under the System Agreement. (LPSC Ex. 86 at Tr. 124-25.)

In addition to the extensive testimony of the above witnesses, the record in ER82-483 contains various sets of minutes of the System Operating Committee from 1961 to 1980. (LPSC Exs. 19-70; OCC Exs. 3-45.) These minutes reveal that the individual companies have had considerable input in the final Committee recommendations, but that it was the Committee that made critical decisions based on the needs of the system as a whole. The minutes show that the Committee members reached conclusions, recommendations, and agreements on a variety of matters such as revised system load and capability forecasts, general geographic locations on the system where new generating units should be located, which companies should tentatively be "assigned" to build certain units, the general size of new units, and allocation of MSE's Grand Gulf capacity.

As previously indicated, Judge Head adopted the position of certain Arkansas parties that there is "autonomy" on the part of the individual operating companies. These parties primarily rely on the fact that Section 4.01 of the 1982 System Agreement requires that each company "own, or have available to it under contract, such generating capability and other facilities as are necessary to supply all of the requirements of its own customers." They argue that all companies fully participate in the consolidated power plan, that the individual companies ask to build new units rather than having units assigned to them, that all final critical decisions regarding generation additions are made by the individual companies and not the Operating Committee, and that the System operates so that the company building a unit shares the new plant only until it can be absorbed by that company's native load. While some of these contentions may be true, neither they nor the above testimony nor the Operating Committee minutes support a finding of autonomy.

As shown in the Operating Committee minutes, there is no doubt that the individual companies have had input in Committee decisions and recommendations, and have actively sought to build certain generation units based on the needs of their individual loads. For example: in 1967, the Operating Committee agreed to AP&L's proposal to build an 800 MW nuclear unit for 1973 (LPSC Ex. 29; OCC Ex. 7); in 1969, the Committee considered company reports regarding the installation of new units for 1975 and 1976, and approved company plans for installation of oil or gas-fired units by MP&L, LP&L and AP&L (LPSC Ex. 35; OCC Ex. 11); and in 1970, the Committee agreed that AP&L should issue a letter of intent for a 1976 load nuclear unit (OCC Ex. 11).

Although the Committee often has concurred in the recommendations and plans submitted by the individual companies, however, the Committee minutes also show that the Committee has not automatically approved individual

company plans and that its recommendations have been made based on overall system needs. For example:

(1) 1966 committee minutes indicate that General Electric and Westinghouse had been requested to submit proposals for a nuclear plant to be operated for the peak of 1971, but it was clearly stated that it was unknown where in the system such unit, if any, would be placed. The companies were notified that their proposals for the unit would be analyzed not only competitively between them, but also from the standpoint of economics with other fuels. The planning committee was to have a report to the Operating Committee on the 1971 unit location. (LPSC Ex. 26; OCC Ex. 4.)

(2) In 1966, LP&L reported that it was investigating the feasibility of installing a unit with a capability of either 550 MW or 750 MW. The Committee indicated that any decision by Louisiana to build a unit larger than 550 MW should be reviewed by the Committee for final approval. (LPSC Ex. 27; OCC Ex. 5.)

(3) In 1967, the Committee agreed that AP&L should install a 750 MW unit at Nine mile Point in 1971 because of the long-range economic benefits to the Middle South System, as determined by studies of alternate sizes and potential load demands. The Committee emphasized its prior agreement that additional capacity must be installed between the New Orleans area and the northern part of the System by 1971. (LPSC Ex. 29; OCC Ex. 7.)

(4) In 1970, the Committee considered a report analyzing various factors associated with adding an 1165 MW 1978 nuclear unit at different locations on the system. These factors included best siting, stress on the transmission system, which company was short or long, etc. The Committee also concluded that if the 1978 unit was located in the south, there would be two nuclear units in the south and two in the north, thereby distributing nuclear energy evenly across the system. (LPSC Ex. 37.)

(5) In 1970, the Committee recommended that because of the tight oil and gas supply situation and need to obtain fuel for 2250 MW of capacity under construction, and expiration of present fuel contracts in 1977, the system should plan for a 1977 peak load nuclear unit in the southern end of the system. (LPSC Ex. 36; OCC Ex. 13.)

(6) In 1976, the Committee directed both AP&L and MP&L to proceed with investigations as though both of them were going to build a 1985 coal-fired unit, even though the preliminary analysis indicated that the unit should be built in Mississippi. The Committee was to later develop a final recommendation as to which company should build the unit. (LPSC Ex. 57; OCC Ex. 32.)

(7) In 1977, the Committee agreed that for forecast purposes, it would be assumed that MSE would own all base load units scheduled for commercial operation in 1987 and later. It recommended to the chief executive officers that all future base load units not yet assigned be assigned in such a manner as to maintain equitable sharing of MSE units (i.e., assign units to levelize capability responsibility deficits insofar as practicable). (LPSC Ex. 60.)

This sampling of Committee minutes supports a finding that decisions on the MSU System are made based on an overall *System* plan and primarily for the system as a whole.

The Arkansas parties argue that new generation units were not assigned, but rather that individual companies volunteered for them. We believe the above evidence supports two major findings: (1) the operating companies were intimately involved in the planning stages of new generation units, sought to meet and promote the needs of their individual systems by "volunteering" to build particular units, and, once the Operating Committee "assigned" a unit to them, exercised their authority to decide details such as specific location, timing, and sizing of the unit; but (2) the Operating Committee nevertheless made the

major decisions concerning general timing, location and size of plant additions, in view of the overall needs of the system, while accommodating individual company needs wherever possible. Whether units were "volunteered" for or "assigned" is not so relevant as the fact that operating companies ended up with responsibility for the units only where all the system companies, jointly acting as the System Operating Committee, concurred that this was in the best interests of the system as a whole.

As previously stated, Section 4.01 of the System Agreement makes each operating company responsible for owning or purchasing capability necessary to meet the requirements of its own customers. In our view, this requirement does not indicate autonomy insofar as final decisions to add generating facilities is concerned. While the companies may have an obligation to volunteer for new units recommended by the Operating Committee or may propose to build units to meet their native load, this does not negate the fact that the overall generation addition plan is reached by consensus of the Operating Committee, and that any proposed new units are approved by the Committee consistent with the overall system objectives.

Still another factor which refutes any contention that AP&L is an autonomous company which plans new units solely to meet its own needs is AP&L's dependence for over a decade on other operating companies to help meet the needs of its native load. This dependence is detailed in both initial decisions, and is amply supported by the records. 26 FERC at p. 65,100 and 30 FERC at p. 65,143.

We note that there appear to be no instances where an operating company has built a new unit without a recommendation to do so from the Operating Committee, or where a company has actually refused to build a unit once the Committee has recommended that it do so. Although some units have had to be cancelled or a company has had to back out of constructing a unit (for example, NOPSI

found it was not feasible for it to construct Grand Gulf 2), these changes in system plans were made with the concurrence of the Operating Committee. (ER82-483 Tr. 4392-93; Tr. 1447-54.)

The "autonomy" argument must also be rejected in part based on the fact that the System Agreement itself removes considerable control from the individual companies. Mr. Trumps testified in ER82-483 that the 1982 System Agreement was changed to provide for decisions by majority vote rather than a two-thirds vote to ensure that one company cannot block a Committee decision. Even under the 1973 Agreement, he agreed, a single company could be outvoted. (Tr. 2545-46.) Although he held the view that new units are not dictated or assigned by the Operating Committee, he stated that once a decision was made, an individual company could not veto that decision. (Tr. 84-85.)

G. The Grand Gulf "Anomaly"

We reject Judge Head's conclusion that Grand Gulf is an "anomaly" to the regular planning and construction of generating facilities on the MSU System. (30 FERC at p. 65,172.) We conclude that the above evidence and the history of generation additions on the System supports a finding that all generation additions, including Grand Gulf, have been planned in basically the same manner.

Both judges provide a good chronology of generation additions on the Middle South System, and their descriptions will not be repeated in detail here. (26 FERC at pp. 65,100-02; 30 FERC at pp. 65,143-45.) Of primary importance in deciding the issues before us is the decision by the System in the late 1960's and early 1970's to change its fuel mix by shifting away from oil and gas generation and obtaining a greater proportion of nuclear and coal generation. Mr. Lupberger testified in ER82-616 that the national natural gas shortage in the 1960's, the loss of long-term gas contracts in Arkansas in the early 1970's

and later at NOPSI, and the Arab oil problems and Federal government push to become less dependent on oil and gas, convinced MSU that fuel diversification was a necessary corporate strategy for building future base load capacity. (Tr. 369.) This strategy is now explicitly stated as a System objective in Section 3.03 of the 1982 System Agreement.

According to Mr. Lupberger, the first step in pursuing the new corporate strategy of fuel diversification was to build the nuclear unit ANO 1. (Tr. 370.) He stated that the decision to build the unit was made on the part of AP&L and the system as a whole. (Id.; Tr. 462.) Mr. Stampley testified that AP&L was the first to install a nuclear unit because it had been a "short" company for at least a decade. (Tr. 823.) Mr. Trumps testified that considerations for installing both ANO 1 and ANO 2 in Arkansas included the facts that Louisiana, Mississippi, and NOPSI had previously installed and operated gas-fired units to serve the entire system, and that AP&L was the first company within the System to lose access to gas contracts. (Tr. 947-48.)

The Arkansas parties argue that the ANO nuclear units were planned and certificated based solely on the need to meet AP&L's load growth. While it may be true that AP&L needed the capacity from the ANO Units,[13] and the APSC may have relied on this need in certificating the units, this does not negate the fact that AP&L's ownership of the units was the result of a joint decision by the System, as part of the overall System generation addition plan. Docket No. ER82-483 contains testimony to this effect by Mr. Phillips, Vice President and Chief Engineer of AP&L, submitted in the State proceedings (U-2286) on ANO 2 and in an environmental report to the Atomic

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[13] AP&L was in a deficit position, as defined in the 1973 System Agreement, from mid-1973 until 1980, when ANO 2 became commercially operational. (ER82-616, Tr. 1995.)

Energy Commission (AEC) on ANO 1. In the ANO 2 State proceedings, Mr. Phillips stated that AP&L's generating capacity is jointly planned with the other Middle South companies and that, in addition to meeting APL&L's needs, the proposed ANO 2 would fit with the reserve requirements of the Middle South System. (APSC Ex. 6 at 23.) He also agreed that responsibility among the sister companies of MSU generally is planned for large facility construction and is done on a rotating basis, and that ANO 2 would be AP&L's contribution for that particular period. (CNO Ex. 51 at pp. 57-62.)

The ANO 1 environmental report submitted by Mr. Phillips to the AEC stated that all generation is planned to meet the forecasted load of the Middle South System as a whole, and that each of the four operating companies constructs generating units to meet the additional requirements of the entire Middle South System. (Staff Ex. 29.) Mr. Ritchie, then president of AP&L, testified in the ANO 1 proceeding before the APSC, stating that the System Operating Committee had determined that it was most desirable to have an 800 MW unit at the time, and that it would not be possible to install an 800 MW unit on the AP&L system if it were not for the interconnected and integrated operation of AP&L with the other MSU companies and interconnections with surrounding utilities in the area. (APSC Ex. 27 at pp. 8-10.)

The above evidence supports a finding that although AP&L alone may have been able to absorb all the capacity of th ANO 1 and ANO 2 units in a very short time,[14] the units nevertheless served not only the individual needs of

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[14] ANO 1 came on line in 1974 and never became a participation unit under the 1973 System Agreement because its total capacity was needed by AP&L. ANO 2 came on line in 1980 and was a participation unit for only two months, until absorbed by AP&L. (ER82-483 MSS EX. 24 at pp. 6-7.)

AP&L, but also the need of meeting overall system load growth and the system goal of diversifying fuel mix.

In September 1970, LP&L announced plans to construct two other nuclear units on the MSU System, Waterford 3 and 4, and in December 1970, filed with the AEC for a construction permit for the units. (ER82-483 Staff Ex. 29.) In its environmental report submitted to the AEC for these units *(id.)*, LP&L noted that the combined load of the System needed the capacity Waterford 3 would provide, and further stated:

> It has been the practice in the Middle South Systems to allocate the new generating unit in any given year to the individual company which shows the greatest deficit in its load and capacity analysis with certain transmission and fuel economic constraints. For 1977 the applicant [LP&L] is the member having the greatest deficit between load and capacity and therefore was the [choice] within the group for installing this additional capacity.

The AEC, in granting a construction permit for Waterford 3, gave great weight to the fact that the unit was needed to furnish power to consumers in the MSU service area.[15]

Also in September 1970, MP&L indicated that it was willing to install the next nuclear unit on the System. Soon thereafter, in February 1971, NOPSI informed the Operating Committee of its desire to build a nuclear unit. (E482-483 Tr. 1528-29.) As indicated in the initial decisions, MP&L and NOPSI originally were each assigned to build a nuclear unit but because of several problems such as siting, responsibility for both units was given to MP&L. MP&L, however, determined that it would be unable to finance one nuclear unit, much less two, and MSE was then formed to own the two units. (26 FERC at pp. 65,101-02; 30 FERC at pp. 65,144-45.)

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[15] *In re Louisiana Power & Light Co.*, 7 AEC 762 (1974).

The evidence supports a finding that the Grand Oil Gulf units were originally planned in the same manner as the other nuclear units, i.e., to meet MP&L's needs to meet System needs, and to meet the System goal of diversifying fuel mix. Mr. Lupberger testified in ER82-616 that initially the driving force behind Grand Gulf 1 was to meet the future load requirements of the System operating companies and the need to move away from dependence on oil and gas. (Tr. 365-66.) Mr. Stampley concurred that the Grand Gulf units were built to meet both System and individual company load growth (in this case MP&L's), as had been true of every unit ever built on the System. (Tr. 746, 756, and 1043.) Mr. Phillips stated in ER82-483 that the Operating Committee decided to go forward with Grand Gulf 2 based on the combined load forecasts of all the companies, not just MP&L's. (ER82-483 Tr. 1547-48.)

The MP&L and MSE joint petition to the MPSC for a certificate of public convenience and necessity stated that the proposed Grand Gulf project would serve as a major source of base load capacity for MP&L and the entire MSS pooling arrangement. (ER82-616 Ex. 46 at p. 13; ER82-483 MSPC Ex. 12.) The MPSC order granting a certificate also stated that the Grand Gulf units would serve as a major source of base load capacity for both MP&L and the entire area served by the Middle South System. (ER82-616 Ex. 80, p. 16.)

There is no doubt that there are difference between Grand Gulf and other System units. These were aptly pointed out in MP&L's brief opposing exceptions in ER82-483, at p. 53:

(1) Every other generating unit on the System has been owned by an individual operating company. No operating company owns any part of Grand Gulf, which is owned separately by MSE.

(2) Every other unit on the System has been built, and is or will be operated, by the company that owns it. MP&L

is the builder and operator of Grand Gulf, but only as the agent of MSE.

(3) Every other unit on the System has been financed by the company that owns it. Grand Gulf is being financed by MSE, but with credit support by *all* the operating companies.

(4) The AEC permits and licenses for other nuclear units on the System were applied for by and granted to a specific operating company. Licensing for Grand Gulf was sought by both MSE and MP&L as co-applicants.

These differences, however, arose solely from the fact that MP&L became unable to finance the Grand gulf units on its own. They do not contradict the fact that Grand Gulf 1 and 2 were planned in the same manner as the other nuclear units on the System.

Mr. Lupberger testified in ER82-616 that the decision to create MSE was made by the Operating Committee, the respective boards of all operating companies, and the parent company.As far as the basic decision to build those units, however, he said the same general process was applied for the Grand Gulf units as for ANO 1 and 2, the difference being that AP&L was capable of financing the ANO units whereas MP&L, NOPSI, or any other operating company was not financially capable of handling Grand Gulf by itself. This, he said, was due to the much lower costs of the ANO units. (Tr. 350-51.)

As pointed out by Judge Head at p. 65,144, the Operating Committee and the financial departments of the operating companies considered joint financing as an alternate to forming the generation subsidiary, MSE. (ER82-483 Tr. 1546-47, 1556.) Consideration was also given to having MSE own all base load capacity subsequent to certain specific units then under construction, which would have resulted in MSE owning basically all new base load capacity and equalization of base load costs. (Tr. 2595,

2701.) MSS Board minutes reveal that MSS also considered a variety of alternative arrangements for ownership of future System generation units, including formation of a generation subsidiary to own only nuclear plants. (See ER82-483 LPSC Ex. 11 (minutes of February 14, 1973)). Any implementation of these ideas was cut short because of financial restrictions placed on MSE by its creditors, prohibiting MSE from embarking on any other construction at least until after Grand Gulf 1 becomes operational. (ER82-483 Tr. 2701.)

Had MSE not been formed, or some other financing arrangement made, it appears that the Grand Gulf units could not have gone forward since none of the operating companies could have independently financed their construction. (ER82-483 Tr. 1545-54.) We conclude that MSE was merely a financing vehicle necessitated by the fact that the Middle South System would have been unable to carry out its generation addition plan without MSE or another financing arrangement. Moreover, there is no reason to believe that the System would not have taken similar steps for any of the other units had the same financial problems prevailed. We therefore conclude that Grand Gulf is not an "anomaly" on the MSU System.

H. Resolution

Our discussion in the preceding section focused on the nuclear plants added to the Middle South System. There are several reasons for this.

(1) The System embarked on a program to carry out a corporate policy, now explicitly stated in Section 3.03 of the 1982 System Agreement, of moving toward a new fuel base of nuclear and coal generation.

(2) The System,along with the nuclear industry nationwide, has been confronted with an unexpectedly dramatic increase in costs, uncertainties and delays in the construction of nuclear plants such as Grand Gulf and Waterford

3. These same problems have not arisen with coal units. (ER82-616 Tr. 800, 843-5, 339-41.)

(3) As recognized by Judges Head and Liebman, MSU System generation costs were roughly equalized among the operating companies under prior coordination agreements, and its is the large cost escalations of Grand Gulf and Waterford that have disrupted this pattern. (Compounding the problem of dramatic cost escalations is the fact that the System overestimated its needs and will have an over bundance of reserves for years to come.) (26 FERC at pp. 65,100-03; 30 FERC at pp. 65,143-46 and pp. 65,168-69.)

(4) A factor differentiating nuclear plants from other plants on the System is location. Historically, a major consideration in determining plant location on the MSU System was access to ready fuel supply. (ER82-483 Tr. 912-13.) This is evidence by the fact, noted by the judges, that in the 1960's and 1970's, System generation was located mainly in Louisiana and Mississippi to take advantage of available fuel supply, particularly low-cost natural gas in Louisiana. Such ready fuel access is not an important factor in locating nuclear plants. *(Id.)*

The evidence cited in the proceeding section reveals a an aggressive attempt by the MSU System to change its fuel base, particularly by adding nuclear generation. It further shows that each operating company was initially assigned at least one nuclear unit. In view of the unforeseen problems unique to constructing nuclear units,[16] and the fact that all Middle South System nuclear units have

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[16] The System Operating Committee recognized the problems unique to nuclear units in 1979 in discussing a 1990 nuclear unit assigned to LP&L. It agreed that because no one company could commit to the uncertainties of nuclear generation under the existing unreasonable lead time, regulatory problems, and financial difficulties, a system study should be done, with the cost of the study to be shared by all the operating companies, and that LP&L should not commit for the unit without further Committee authorization. (ER82-483 Ex. 64.)

been planned to meet overall system needs and objectives, we conclude that some form of equalization of nuclear plant costs is necessary to achieve just reasonable, and non-discrminatory rates among the MSU operating companies.[17]

The question before us is whether the 1982 System Agreement and the UPSA, as filed, together will achieve proper cost allocation. We conclude that they will not, but that the 1982 System Agreement in conjunction with Judge Liebman's allocation of nuclear capacity will achieve just and reasonable results. We affirm and adopt Judge Liebman's findings and conclusion that the proposal of the LPSC and OCC is the most equitable allocation proposal in the ER82-616 record, and that the Grand Gulf allocation therein will result in an equitable sharing of responsibility for all the nuclear capacity on the MSU System. Judge Liebman provides a sound basis for his conclusion and a thorough analysis of the other allocation proposals at pp. 65,109-13 of his initial decision, and his discussion will not be repeated here.

The LPSC and OCC proposal adopted by Judge Liebman, contained in Exhibit 124, determines Grand Gulf 1 allotments in a manner designed to equitably apportion throughout the pool the total nuclear investment costs of the Middle South System. Exhibit 124 derives the total investment provided by AP&L's ANO 1 and 2, LP&L's Waterford 3, and MSE's Grand Gulf 1 nuclear units (as of the date of record). Based on the respective 1982 av-

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[17] We note that major nuclear plant construction problems arose after the ANO units, which basically were pre-Three Mile Island regulations and prior to the major cost escalations and delays experienced by the nuclear industry in general. (ER82-616 Tr. 2199-2200.) However, based on our previous finding that the ANO units were part of the *System* plan to embark on a program to move away from oil and gas base load generation, we conclude that the costs of all nuclear units, including the ANO units, should be equalized in an equitable manner.

erage demand to average system demand ratio for each pool member, the exhibit determines each member's total average nuclear investment responsibility. Each member's nuclear investment responsibility is then compared to its owned nuclear investment. The shortfall between a member's owned nuclear investment and the proportionate assignment of average nuclear investment to that member represents the amount of Grand Gulf 1 investment to be allotted to that member. This investment differential is converted into MW's of Grand Gulf capacity and, ultimately, into Grand gulf percentage entitlements.

The Grand Gulf allocation percentages derived in Exhibit 124, and adopted herein, are as follows:

AP&L	36%
LP&L	14%
MP&L	33%
NOPSI	17%
	100%

As indicated by Judge Liebman, this allocation will result in each company sharing the cost of nuclear capacity roughly in proportion to each company's share of System demand.[18]

The impact of these Grand gulf allotments (or any other Grand Gulf allotments) on reserve equalization under Service Schedule MSS-1 of the 1982 System Agreement will likely be a change in the shortness or longness of each member. For example, when Grand Gulf 1 becomes commercially operable, to the extent that the fixed Grand Gulf

[18] As pointed out by Judge Liebman, this proposal's focus on nuclear capacity does not disregard other System base load capacity since it recognizes that while there are some differences in the costs of non-nuclear generation among the companies, these cost differences are relatively minor compared to the cost differences for nuclear generation. (26 FERC at p. 65,110.)

allotment ratio exceeds (or is exceeded by) the monthly 1982 System Agreement responsibility ratio for a given pool member, that member will become either more long (or short) or less long (or short) for pool reserve equalization purposes. the excess capacity of the long members will be equalized in accordance with the 1982 Agreement, i.e., to the extent a member having excess capacity cannot reach voluntary agreements to sell its excess capacity and energy under Service Schedule MSS-4 (Unit Power Purchase), its excess capacity will be equalized among the short members based on the costs of the long member's intermediate generating units under Service Schedule MSS-1 (Reserve Equalization). Any excess energy will be shared with the pool under Service Schedule MSS-3 (Exchange of Electric Energy Among the Companies).

We conclude that the above Grand Gulf allocation, coupled with the operation of the 1982 System Agreement, will result in just, reasonable, and non-discrminatory rates for the MSU Operating companies. We affirm and adopt Judge Head's findings and conclusions rejecting the various allocation proposals in the ER82-483 record, and his approval of the 1982 System Agreement, except to the extent that he finds there is autonomy on the System or that the generating units are not planned and constructed for the System as a whole.[19]

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[19] Specifically, we agree with Judge Head's rejection of the MPSC proposal to reinstate the participation unit concept. As found by the judge at pp. 65,166-67 of the initial decision, the MPSC proposal would be inequitable and discriminatory because it would result in MP&L avoiding all responsibility for Grand Gulf for approximately 10 years, after which time it would enjoy the benefits of the project in the less expensive years. In the meantime, the short companies (LP&L and NOPSI) would pay approximately $3 billion of Grand Gulf's costs.

As to the production cost equalization proposals, we do not find it appropriate or necessary to adopt any of those proposals since they would be a substantial change from the way costs previously have been allocated on the MSU system, and since the allocation adopted herein

We next address the relationship between the stated objectives of the 1982 System Agreement and our decision herein. The Agreement lists several major objectives, including:

(1) the planning, construction and operation of bulk power supply on a coordinated basis;

(2) the equalization among the operating companies of any imbalance of costs associated with the construction, ownership and operation of such facilities as are used for the mutual benefit of all the companies;

(3) the need of the companies to move toward a new fuel base of coal and nuclear generation;

(4) the long-term goal that each company will have its proportionate share of base load generating units (coal and nuclear) available to serve its customers either by ownership or purchase, and

(5) the intention that each company will be willing and able to provide its portion of the major facilities determined to be necessary, and to share in the benefits and pay its share of the costs of coordinated operation as agreed upon.

We find these System goals to be reasonable and conclude that the allocation recommended by Judge Liebman is consistent with and will promote the System's major objectives. Most importantly, the allocation adopted herein will equalize the imbalance of costs resulting from nuclear units planned and constructed by and for the System as a whole, and will promote the System goals of increasing

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will ameliorate the cost disparties among the operating companies.

We reject Judge Head's recommended Grand Gulf allocation as inconsistent with our conclusions that Grand Gulf is *not* anomaly on the System, and that equalization of *all* nuclear costs is necessary to achieve just, reasonable, and non-discriminatory rates.

the System's nuclear fuel base as well as each company's proportionate share of nuclear fuel base.

One final matter concerns the suggestion by some of the Louisiana parties, in briefs on and opposing exceptions in Docket No. ER82-483, that if Judge Liebman's Grand Gulf allocation is adopted, then updated cost estimates for the Grand Gulf and Waterford nuclear units should be used. Because cost estimates for these units have been continually changing and because the costs as well as demand projections in ER82-616 were reasonable when made and were subject to cross-examination, we find it appropriate to adopt Judge Liebman's recommendation without modification at this time.

II. ER82-616 Rate Issues

In addition to setting forth the purchasers' entitlements to the output of Grand Gulf, the UPSA also establishes the rates that each purchaser will pay to MSE. The parties have raised a number of issues concerning these rates, all of which were thoroughly addressed by Judge Liebman. We affirm the judge on all issue, except for rate of return (discussed in Section IV, *infra*), depreciation, annual amount of decommissioning expense, amortization of limited-term electric plant, and use of an income tax formula.[20]

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[20] We summarily affirm the judge on his decision to: (1) defer the approval of rates for Grand Gulf Unit No. 2; (2) allow MSE to include $5 million in property taxes in its estimate of total decommissioning expense; (3) require MSE to use an external sinking fund for accumulating decommissioning amounts; and (4) exclude from the formula rate customer service and sales expenses.

In reference to the issue of whether MSE should be required to periodically re-file the formula rate, we agree with and adopt those portions of the initial decision in which the judge held that, for the reasons given in *Middle South Services Inc.*, Opinion No. 124, 16 FERC ¶61,101 (1981), *aff'd sub nom. Louisiana Public Service Comm'n v.*

A. Depreciation

During the initial period of Grand Gulf's operation, MSE proposes to calculate depreciation by the units-of-production (UOP) depreciation method, a method which determines depreciation per kilowatt-hour. After the initial shakedown period for the plant, MSE proposes to use the equal life group (ELG) depreciation method, under which plant components are segregated on the basis of their expected service lives and the investment in each group is amortized over its assigned life. The UOP and ELG methods are described in detail in the initial decision, 26 FERC at pp. 65,132-33.

Trial Staff was the only participant to object to MSE's proposed depreciation methods. The judge rejected Staff's argument against using the UOP method for Grand Gulf 1 during its initial operation, but held that in no event should the method be used for more than five years. He also rejected Staff's arguments against using the ELG method.

On exceptions, Staff states that while it does not object to the use of the UPO method for limited periods of time, the method should be used only for six to twelve months. It gives five reasons: (1) straight-line depreciation, and not the UOP method, is the generally accepted depreciation method or electric utilities; (2) the judge apparently presumes that Grand Gulf may need a shakedown period of up to five years, but the shakedown should be effectively completed within 12 months after the unit goes into commercial operation; (3) straight-line depreciation is much simpler to implement because it involves making only one

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F.E.R.C., 688 F.2d 357 (5th Cir. 1982), *cert. denied*, 103 S.Ct. 1770 (1983), and *Southern Company Services*, 22 FERC ¶61,047 (1983), MSE need not re-file the formula periodically. (26 FERC at pp. 65,147-48.) However, we do not agree with, and do not adopt, those portions of the initial decision in which the judge suggested that such filings are necessary. (26 FERC at pp. 65,146-47.)

estimate (remaining plant life) whereas the UOP method involves making two estimates (remaining plant life and capacity factor at which the plant will operate); (4) a NARUC report criticizes the use of the UOP method; and (5) in Staff's view, the Commission has looked with disfavor on the type of intergenerational equity which MSE wants to achieve, i.e., to use the UPO method to reduce charges under the UPSA during he first several years of operation in order to reduce the impact of rate increases needed to compensate for the costs of Grand Gulf 1 power during that time.

We find that the judge's acceptance of the UOP depreciation method in conjunction with a cost of service tariff is acceptable in principle, if the method is used only for a limited time period. The judge himself recognized that the UOP method should be applied only for the initial shakedown period of Grand Gulf 1, but nevertheless approved its use for up top five years. Because a shakedown period normally is approximately 12 months, and the UPO method is not the depreciation method that has been generally accepted by this Commission, we find that the initial decision should be modified to allow the use of the UPO method for no longer than 12 months. However, MSE will not be precluded in a future proceeding from seeking to extend this time period should the shakedown period actually take longer than 12 months.

Staff also excepts to the judge's acceptance of the use of the ELG method of depreciation after the initial shakedown period. It argues that ELG rates have not been accepted by the Commission in any previously litigated electric rate case, and that MSE did not meet the requirements for using the ELG method. Specifically, Staff claims that MSE identified property only in broad five-year increments; that it did not identify the units that would be grouped together with the same service lives; and that because Grand Gulf 1 is a new nuclear unit, MSE does not have good mortality data for judging how re-

tirements of various plant components tend to be distributed by age, which is necessary for the ELG approach to be feasible.

While the ELG depreciation method may be technically possible to implement, we are concerned that it will inhibit our ability to effectively monitor MSE's depreciation expense, particularly because the method involves many different depreciation rates and different groups of equipment being retired at different times. We have not previously accepted this depreciation method in a litigated electric rate case, and decline to do so here. Accordingly, MSE is directed to begin using the conventional straight-line depreciation method at the end of the initial 12-month period during which it is allowed to use the UOP depreciation method.

B. Annual Amount of Decommissioning Expense

A utility operating a nuclear generating unit eventually will incur the cost of decommissioning the unit. Since this is a cost of providing service from the unit, a portion of the total cost is chargeable each year to the ratepayers. The judge rejected MSE's proposal that the annual amount for Unit No. 1 should be set at an artificially low level of $324,000 during the first few years of the unit's life and then be allowed to rise. Instead, he adopted Staff's proposal that the annual amount of decommissioning expense be the same each year. This amount, the judge held, would be $1,236,876.

On exceptions MSE raises two points. The first is that the judge erred in adopting Staff's proposal. MSE argues that its proposal is preferable because the annual amount of decommissioning expense initially should be set at a low level. We disagree. The costs of decommissioning Grand Gulf are costs that are incurred in providing service from it. The ratepayers who take that service are responsible for those costs, and the principles of cost-based ratemaking suggest that ratepayers who take service now bear the

same relative decommissioning burden as those who take service later.[21] Staff's proposal carries out this objective. MSE's does not. We therefore affirm the judge's adoption of Staff's proposal.

MSE's second point is that, notwithstanding the merits of the issue, the judge erred in calculating the annual amount of decommissioning expense. This is correct. The judge used 100% of the total cost of decommissioning Unit No. 1 in calculating the annual amount. MSE, however, owns only 90% of Unit No. 1 and is expected to pay only 90% of the total cost of decommissioning that unit. (Ex. 49, p. 2; Ex. 22, p. 13.) The annual amount of decommissioning expense to be included in MSE's rates should therefore be calculated using the latter amount. The annual expense so calculated is $1,113,188.[22]

C. Amortization of Limited-Term Electric Plant

The judge permitted the formula rate to provide for amounts recovered in Accounts 404-407 and Accounts 411.6 and 411.7, but also held that no amounts could be recorded in these accounts without prior approval by the Commission. (26 FERC at pp. 65,148-49.)

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[21] These general principles are discussed in *Columbia Gulf Transmission Co.*, Opinion No. 173, 23 FERC ¶61,396, at pp. 61,850-51, *appeal docketed sub nom. City of Charlottesville v. F.E.R.C.*, No. 83-2059 (D.C. Cir. filed Oct. 6, 1983); *Tax Normalization for Certain Items Reflecting Timing Differences in Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, FERC Statutes and Regulations ¶30,254 (1981), *reh. denied*, Order No. 144-A, *FERC Statutes and Regulations* ¶30,340 (1982), *aff'd sub nom. Public Systems v. F.E.R.C.*, 709 F.2d 73 (D.C. Cir. 1983).

[22] We note that although MSE's decommissioning cost estimates may be reasonable at this time, the company may seek adjustments to those estimates as more updated cost information is obtained. See *Commonwealth Edison Co.*, Opinion No. 165, 23 FERC ¶61,219 (1983), in which we held that Commonwealth Edison was not only free to seek, but was obligated to seek, adjustments to its depreciation rates as more updated depreciation information was obtained, in order to assure as near as possible full recovery of the costs of electric plants.

MSE excepts insofar as the judge required prior approval for amounts to be recorded in Account 404 (Amortization of Limited-Term Electric Plant). It claims that this is not consistent with the Uniform System of Accounts. The Uniform System of Accounts requires Commission approval before recording amounts in Accounts 405-417 and Accounts 411.6 and 411.7. It does not, however, require utilities to obtain our approval before recording amounts in Account 404.

No party has given any basis to be concerned that MSE would not use Account 404 properly. We therefore modify the initial decision such that MSE would not use Account 404 properly. We therefore modify the initial decision such that MSE will not be required to obtain prior Commission approval for amounts included in Account 404.)

D. Income Tax Formula

No party in this docket disputed MSE's use of tax normalization in determining its cost of service rates. Staff, however, suggested that a modified version of MSE's sample calculation of income tax expense be incorporated in MSE's proposed billing format, thereby becoming a formulary tax component of the UPSA.

The judge rejected this suggestion, finding that "Staff has offered no reason to support the inclusion of a tax formula, nor has provided any support for the use of the sample calculation of income tax as a surrogate or an algebraic formula." (26 FERC at p. 65,143.) He noted that Staff had not cited any other unit power sales agreement on file with the Commission in which income taxes were represented in the rates by an algebraic formula such as that suggested by Staff. *(Id.)* Because MSE's sample calculation reflected uncertainty as to whether operations of Grand Gulf 1 would be subject to Mississippi income taxes, he further found that it could be inappropriate to attempt to fashion a tax formula to be included in the billing format prior to the time questions regarding the applicability of Mississippi income taxes are resolved. *(Id.)*

Staff excepts to the judge's ruling, claiming that it is important to set out a detailed calculation of both State and Federal income taxes in order to insure that MSE continues to compute income taxes incorporating tax normalization methods. Staff argues that MSE should be required to attach to its monthly billing statement to each operating company a step-by-step calculation of income tax expense as set out in Exhibit 72 (MSE's sample calculation of income taxes), since MSE will have to perform these calculations in any event and it would aid our accounting staff in verifying MSE's tax computation methods.

Although no party has argued that MSE will not properly normalize its income tax expense if a detailed formula is not included in the UPSA, we are concerned that we will not have an adequate opportunity to review the tax expense in MSE's rates unless some sort of sample tax calculation is provided to us. The Commission's general practice in recent years has been to require newly filed long-term unit power sales agreements to include a detailed tax computation as the tax component of the monthly billing statement.[23] This results in greater accountability of a utility in serving its unit power customers, and places no additional burden on the utlitiy since it must make those detailed calculations in any event. According, we direct MSE to submit to us for approval a revised billing format, with an algebraic tax formula and an accounting treatment showing the detailed computation of the cost of service tax component.[24]

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[23] *See* South Carolina Generating Co., Inc., Rate Schedule FERC No. 1; AEP Generating Co., Rate Schedule FERC nos. 1, 2, and 3.

[24] It has been argued that an algebraic formula is inappropriate because there is an unresolved question as to whether Grand Gulf 1 will be subject to Mississippi income taxes. To the extent that MSE is found not to be subject to Mississippi State income tax, this should be appropriately reflected in the rates.

III. ER82-483 Rate Issues

In the proceeding concerning the 1982 System Agreement, Judge Head decided a procedural question (Tr. 1382-84) and six miscellaneous rate issues (30 FERC ¶63,030, at pp. 65,131-39) to which exceptions have been filed. We affirm the initial decision with respect to four of the six miscellaneous issues.[25] We modify the initial decision with respect to Service Schedules MSS-3 and MSS-1, and we deny the exceptions to Judge Head's bench ruling in which he denied the admission of certain surrebuttal testimony, as discussed below. In this section we also affirm the judge on a further issue involving "time dating" of capital structure costs in Schedule MSS-4.

A. Service Schedule MSS-3 Adder

Service Schedule MSS-3 contains provisions governing the exchange and pricing of energy among the MSU operating companies. Energy is allocated on an hourly basis from the lowest cost sources, first to the loads of the companies owning the sources and second to the pool. The company that supplies energy to the pool is reimbursed for the current estimated cost of fuel, plus an adder determined by an algebraic formula in Section 30.08(f) of Service schedule MSS-3. The MSS-3 adder is designed to reimburse the producing company for the incremental O&M costs associated with the production of additional energy.

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[25] We summarily affirm the initial decision with respect to its holdings that: (1) approval of the "cost of service" tariff represented by Service Schedules MSS-1 (Reserve Equalization), MSS-2 (Transmission Equalization), MSS-3 (Exchange of Electric Energy), and MSS-4 (Unit Power Purchase) will not be made subject to periodic review conditions; (2) the designation of transmission facilities (as Inter-Transmission Investment) in the cost equalization formula in Service Schedule MSS-2 is justified; (3) MSS's classification of intermediate generating units on the basis of fuel should be approved; and (4) MSS is justified in its allocation of administrative and general expenses to pool transactions and its use of labor ratios as the basis for doing so. (See 30 FERC ¶63,030, at pp. 65,131-37.)

The initial decision held that the MSS-3 adder was just and reasonable and that no strict cost support was required. The judge held that the operating companies should be allowed to recover their hard-to-quantify O&M costs through an adder. He found that the adder is analogous to the percentage adders allowed by section 35.23 of the Commission's regulations. Addressing CNO's concern that the adder provided for no cap, the judge stated that in *Ohio Edison Co.*, 23 FERC ¶61,344 (1983), the Commission approved the use of an uncapped 10% adder to recover hard-to-quantify, incremental O&M expenses without requiring strict cost support. (30 FERC ¶63,030, at p. 65,138.)

On exceptions, CNO repeats its claim that the adder lacks necessary cost justification. CNO contends that Order No. 84,[26] which established section 35.23 concerning percentage adders, is not applicable to the instant case, because no transmission arrangements are at issue here and the costs collected by the adder were not calculated as a percentage of purchased power costs as was contemplated in Order No. 84. CNO contends that the reasonableness of the 1 mill threshold endorsed by Order No. 84 does not prove the reasonableness of an adder for unquantifiable O&M expenses in this case. CNO further contends that the uncapped MSS-3 adder conceivably could exceed the level of reasonableness endorsed by Order No. 84. Finally, CNO claims that the MSS-3 adder may allow for the double recovery of costs, contending that O&M costs of intermediate generation are subject to collection through the reserve sharing provided in Service Schedule MSS-1. MSS opposes CNO's exceptions, following the rationale of the initial decision.

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[26] Order No. 84, Limits for Percentage Adders in Electric Rates Transmission Service, Docket No. RM79-29, 45 Fed. Reg. 31,294 (1980) (*reh. denied* 12 FERC ¶61,017 (1980); further clarified in 12 FERC ¶61,157 (1980)). Order No. 84 also appears in FERC Statutes and Regulations, Regulations Preambles, 1977-1981 ¶30,153 (1980).

CNO's argument that section 35.23 is not directly applicable to the instant case has merit. In the preamble to section 35.23 in Order No. 84, the Commission noted that the "proposed rule was designed to limit percentage adders in all electric rates according to whether a utility generated the electric power delivered or only transmitted it through an interconnection agreement." (*FERC Statutes and Regulations, Regulations Preambles, 1977-1981* ¶30,153, at p. 31,031.) However, the notice and comment procedures yielded little cost data from which the Commission could have established a reasonable limit on generation adders, percentage adders that are used by utilities that so the rulemaking focused on percentage adders that are used by utilities that perform transmission or purchase and resale functions in multiple party transactions. (Id.) The Commission stated that it:

> continues to study the appropriateness of percentage adders when used for the primary generation of power and the interchange generation functions of transmitting utilities where the charge added to the overall charge for the power transmitted is based only on the internal incremental costs incurred by the transmitter.

(*Id.* at p. 31,035.) Thus, section 35.23, as established by Order No. 84, was intended to apply only to adders on third-party wheeling and multiple party purchase and resale transactions. MSS's transactions, in contrast, concern the sale of generation, and generation adders are not addressed by section 35.23. In view of this finding, *Ohio Edison,* cited by the initial decision as allowing uncapped percentage adders, does not apply to the instant case in the context of adders permitted by section 35.23. Further, in *Ohio Edison,* the uncapped adder served as a penalty to prevent abuse of emergency power service. 23 FERC ¶61,344, note 5 at p. 61,754. Such a rationale is absent here.

However, despite the foregoing, we nonetheless believe that the initial decision reached a correct result. MS's cost plus a formula adder appears reasonable overall. First, the use of an adder is supportable here in principle, because adders are typically permitted for the recovery of difficult-to-quantify incremental costs. No party disputes that MSS's incremental O&M costs are difficult to quantify. Second, we believe that it would be inappropriate for MSS to use a percentage adder to recover such costs. Although a percentage adder is common industry practice in interchange transactions,[27] it would not serve the typical policy objectives in this case. In *Ohio Edison,* the Commission stated that in coordination transactions, an adder is allowed as an incentive to the selling utility to engage in such transactions. The Commission noted that, without some incentive above its incremental costs, a utility has no reason to undertake a coordination transaction and that such transactions usually reduce the cost of service to the buying utility and thus the ultimate consumer. (*Ohio Edison, supra,* at p. 61,749.) However, we believe that no such incentive structure exists between the affiliated Middle South companies, because the interchange transactions are wholly within the integrated System, are centrally dispatched, and are mandated by MSS rather than the individual companies. Thus, the operating companies do not require the incentive of a percentage adder in order to engage in these transactions.[28] third, we believe that it is unnecessary for MSS to furnish specific cost support for the MSS-3 adder. Notwithstanding the fact that section 35.23 of our regulations governs another type of utility

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[27] *See* Ohio Edison Co., Initial Decision, 15 FERC ¶63,062, at p. 65,304 (1981), affirmed in part, and reversed in part in Ohio Edison Co., Opinion No. 170, 23 FERC ¶61,344 (1983); and Indiana & Michigan Electric Co., et al, 12 FERC ¶61,167, at p. 61,405 (1980).

[28] The issue of pricing in interchange transactions, among other things, is presently under review by the Commission. (See Notice of Inquiry, Docket No. RM85-17 (issued May 30, 1985).)

service, the section is nonetheless instructive in evaluating the present case. Section 35.23 reflects the general principle that, as an administrative convenience, we would not consider it cost-effective to require a utility to attempt to provide particularized support for difficult-to-quantify incremental costs as low as one mill per kWh.[29]

Under MSS's formula, it does not appear likely that the MSS-3 adder would exceed this one mill level.[30] Nor is the MSS-3 adder likely to produce as great a charge as would a ten percent adder. The MSS-3 adder appears to be MSS's attempt to determine its difficult-to-quantify incremental costs with some degree of accuracy. The charge produced using the adder is based on the ratio of current to base period incremental O&M costs as indexed in the formula. Thus, significant sudden increases in the adder appear unlikely. In contrast, an uncapped percentage adder would increase in proportion to the total costs on which it is based. Thus, with a percentage adder, it is possible that the amount recovered by the utility would increase at a more rapid rate than the unquantifiable costs which the charge is intended to collect.[31]

We reject CNO's allegation of possible double recovery of costs under the MSS-3 adder, because each of the MSS Service Schedules applies to different pooling functions. Thus, the *same* costs are not being recovered twice. Accordingly, we agree with the initial decision that the MSS-3 adder is justified and that no cost support need be filed at this time. However, if the MSS-3 adder should, at some future date, exceed a charge of one mill per kWh—or such

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[29] See *FERC Statutes and Regulations, Regulations Preambles*, 1977-1981, *supra*, ¶30,153, at p. 31,034.

[30] For example, in order for the formula adder to exceed one mill per kWh, MSS's current incremental O&M costs would have to nearly double the O&M costs for the relatively recent base period.

[31] *See Ohio Edison Co.*, Initial Decision, 15 FERC ¶63,062, at p. 65,304 (1981).

charge as the Commission may ultimately rule to be determinative of whether cost support is required for generation adders in interchange sales, generally—then action may be taken at such time to require cost support for the adder. Therefore, we affirm the initial decision, as modified here.

B. Service Schedule MSS-1 Adder

The MSS-1 adder gives credit to the operating companies, for reserve equalization purposes, for the value of capacity backed by reserves, which is purchased from non-affiliated utilities. The adder is calculated in accordance with an algebraic formula.

The initial decision approved the inclusion of the MSS-1 adder in the 1982 System Agreement. (30 FERC ¶63,030, at pp. 65,138-39.) On exceptions, CNO contends that the judge ignored the potential risk of disproportionately high credits to the purchasing utility under the sliding scale used in the adder and the fact that the adder treats sales of the same amount of energy differently. CNO questions the fact that the adder is affected by the amount of reserves on the Middle South System rather than those of the foreign seller which the adder is intended to reflect. CNO has also proposed subtraction of the amount of reserves that a Middle South company loses in a firm sale to a foreign utility, contending that MSS's failure to do so is discriminatory. Finally, CNO alleges that the adder provides an incentive to the operating companies to purchase firm power from outside the system despite "tremendous" reserves on the system.

We believe that the judge properly found that credit for the reserves associated with firm purchases is appropriate. Firm purchased capacity provides its own reserves and generally is more valuable than capacity not backed by reserves (such as unit power purchases). However, we also believe that CNO's alternative argument that the adder should reflect the *supplier's* reserves has merit. It appears

more appropriate to fix the percentage credits for reserves so that they reflect the reserve level of the supplier; this avoids the possibility, using MSS's sliding scale reserve mechanism, that credit could exceed 100 percent of the capacity purchased. (*See* CNO Ex. 3, p. 36; Tr. 2089-91.) Therefore, we direct MSS to revise the MSS-1 adder to fix the percentage credits for reserves so that they reflect the reserve level of the supplier.

Regarding CNO's argument that there should be a subtraction of reserves for firm sales to foreign utilities, it appears correct, as argued by MSS and agreed to by Judge Head, that such a condition is unnecessary. MSS argued that firm sales would increase the selling company's Load Responsibility, thereby increasing its proportionate share of reserves, which would result in a reduction of the company's reserve equalization receipts and an increase in its payments. (MSS Reply Br., pp. 6-7; Initial Decision, 30 FERC ¶63,030, at p. 65,139.) Thus, there appears to be no undue benefit to an operating company making firm sales, and a penalty for such sales, as proposed by CNO, is unwarranted. Accordingly, we affirm the initial decision on the MSS-1 adder issue, as modified herein.

C. Capital Structure

Schedule MSS-4 permits MSU's operating companies to purchase capacity from a designated generating unit of another operating company. The judge accepted MSS's practice in Schedule MSS-4 of reflecting, in its monthly billing charge, the selling company's individual capital structure costs of embedded debt and preferred stock associated with the construction period of the designated generating unit from which the sale is made.

CNO excepts to the judge's adoption of the time dating practice, contending that the practice is not widely accepted and may result in under collection or over collection of revenues from various customer classes. In response, MSS argues that the practice of time dating is consistent

with the narrowly defined purpose of Schedule MSS-4 to base charges on the costs of a contractually designated unit. MSS contends that the MSS-4 procedure represents a carry-over of the procedures used in MSS-1 of the 1973 System Agreement for participation units, and that the Commission granted implicit approval of that procedure in *Middle South Service, Inc.*, 16 FERC ¶61,101 (1981).

We agree with the judge that the practice in Schedule MSS-4 of basing charges on the capital costs of a designated generating unit is consistent with the Commission's ruling in the prior MSS proceeding. Moreover, the use of this procedure for purposes of pricing individual unit power sales has previously been approved by the Commission.[32] Consequently, we affirm the judge's conclusion on this issue.

D. Surrebuttal Testimony

Surrebuttal testimony was filed by the Commission's Trail Staff, CNO, LPSC, and Occidental Chemical Company (OCC) in September 1983. Except for a portion of OCC's surrebuttal testimony, which was admitted on October 26, 1983 (Tr. 2375), all of the surrebuttal testimony was rejected by Judge Head in rulings from the bench during the evidentiary hearing session of October 11, 1983. (Tr. 1259-1384.)

OCC's surrebuttal, which consisted of 40 pages of testimony by Mr. Nathan, an economist, was intended to respond to contentions made in the rebuttal testimony of various witnesses representing MSS and several Arkansas interests. That testimony concerned the equity and efficiency of the cost equalization provisions. The judge denied admission of page 1 through most of page 31 of Mr. Nathan's testimony. (Tr. 1383.)

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[32] *See, e.g., Connecticut Light and Power Co.*, Opinion No. 701 52 FPC 175 (1974); *Public Service Co. of New Hampshire*, 20 FERC ¶63,015 (1982), *aff'd*, 22 FERC ¶61,229 (1983).

The judge based his decision on considerations of disruption to the administrative process and fairness to the other parties. (Tr. 1382-84.) Specifically, Judge Head found that OCC could have either filed testimony regarding the effect of MSS's proposal at an earlier date or, at least, moved earlier rather than waiting until the eve of trial to present such testimony. (Tr. 1382.)[33] Further, the judge noted that it would be unfair to the other parties to allow OCC to "wait until all of the other parties have had their say on what is a rather critical issue . . . and then have the opportunity to come in with the benefit of having everybody else's views on the table and express their opinion." (Tr. 1382.)[34] Addressing LPSC's motion, the judge also noted that surrebuttal testimony was not mentioned in the procedural schedule. (Tr. 1379.) Further, he stated that "there was ample time to have moved in advance to revise the procedural schedule if there was some perceived unfairness in connection with the way that testimony was filed back in July and August." (Tr. 1383.) The judge held that it was too late for OCC to seek to amend the procedural schedule to permit the filing of the surrebuttal testimony. (Tr. 1383.)

OCC did not seek to appeal the judge's evidentiary ruling to the Commission. However, on exceptions, OCC contends that the rebuttal testimony filed by MSS in August, 1983, was substantially more extensive than testimony originally submitted in support of the 1982 System Agreement as filed and that OCC's surrebuttal testimony was directly relevant to issues raised in MSS's rebuttal testimony. OCC maintains that admission of the surrebuttal testimony would not have delayed the ultimate resolution of this case and that the integrity of the procedural schedule should not *per se* have barred such important testimony from being submitted.

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[33] The evidentiary hearing began on September 29, 1983.

[34] OCC did not file direct testimony.

In a jointly filed brief opposing exceptions, the Arkansas and Missouri Public Service commissions contend that if the surrebuttal testimony is admitted, then due process would require that the record be reopen in order to allow for written responses and cross-examination. The Arkansas and Missouri Congressional Delegations adopted the Arkansas and Missouri Commissions' brief. The State of Arkansas Office of the Attorney General also opposes OCC's exceptions.

Implicit in Judge Head's ruling is that he distinguished the excluded portion of OCC's surrebuttal testimony from the admitted portion based on this opinion that: (1) the admitted testimony was not contained elsewhere in the record, and (2) thee was "countering type testimony" on the part of certain of the Arkansas parties concerning a relevant issue in the case which the admitted surrebuttal addressed. (Tr. 1383, 2375-76.)

OCC has not demonstrated how the excluded portions of its surrebuttal may have changed the judge's analysis in the initial decision. Further, as the judge noted, the conclusive nature of the arguments made in OCC's surrebuttal testimony make them more appropriate or a brief than as expert testimony. (See Tr. 1353.) Finally, the admission of part of OCC's surrebuttal testimony indicates that the judge's desire to maintain the integrity of the procedural schedule did not serve as a *per se* bar to the surrebuttal testimony. We believe that Judge Head equitably balanced the interests of having a complete record (Tr. 1383-84), the interests of fairness to all parties, and the integrity of the administrative process (Tr. 1382-83), and we believe that he arrived at a sound ruling. Further, since no other parties who originally sought to introduce surrebuttal testimony have filed exceptions on this issue, we see no need to address OCC's additional request that those parties' surrebuttal testimony be admitted also. For the reasons stated, we deny OCC's exceptions to the judge's ruling on surrebuttal testimony.

IV. Rate of Return on Equity

We have before us a ratemaking scenario that is novel in several respects. First, we are evaluating two records and two sets of rates for MSU companies in tandem, and in each case MSU is used as a proxy for its subsidiaries in determining capital costs. Second, and even more significant, the older of the two evidentiary records (ER82-616) applies to rates that will take effect prospectively and well after the rates at issue in the other record (ER82-483). In essence, we are confronted with the same basic rate of return studies updated over a continuing period (i.e., the ER82-483 record updates the ER82-616 data).

The same staff witness, Mr. Randall, presented rate of return recommendations in both dockets, based primarily on DCF analyses. The judge in each of the dockets accepted Mr. Randall's DCF analysis and adopted his recommendation, except that Judge Head in ER82-483 raised the staff recommendation based on certain changes occurring after the close of the record. (26 FERC at pp. 65,124-32; 30 FERC, at pp. 65,123-30). We affirm the rationale and conclusions of the judges in adopting Mr. Randall's methodology and rejecting the other record approaches as deficient.[35]

Having accepted Mr. Randall's methodology and assumptions, we must still determine what return on common equity is most representative for the periods during which the rates will be in effect.[36] Given the updated in-

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[35] We do not agree, however, with Judge Liebman's conclusion that the range of reasonable returns in Docket No. ER82-616 is as limited as he determined, i.e., 15.9% to 16.2%. 26 FERC at pp. 65,131-32.

[36] For examples of cases in which the Commission has emphasized the need to determine a rate of return reflective of the period covered by the rates (and in doing so, evaluated post-record data), *see Illinois Power Co.*, 15 FERC ¶61,050 (1981); *Pacific Gas and Electric Co.*, Opinion No. 143, 20 FERC ¶61,190 (1982); *Minnesota Power and Light Co.*, Opinion No. 155, 21 FERC ¶61,233 (1982); and *Public Service Co. of New Mexico*. Opinion No. 164, 23 FERC ¶61,218 (1983).

formation that has been made available through he course of these proceedings and the fact that the rates in ER82-616 have not yet take effect, we believe that the single rate of return adopted in this opinion on the basis of the cumulative information available in the records is appropriate for both dockets and both effective periods

The hearing in ER82-616 began on March 14, 1983. Mr. Randall originally recommended a return on equity of 16.13% but, based on an updated DCF study, lowered his recommendation to 16.4% prior to the close of the record on May 12, 1983. The hearing in ER82-483 began on September 29, 1983. In that case, Mr. Randall originally recommended a return on equity of 15.86% but, based on an updated DCF study, lowered his recommendation to 15.35% prior to the close of the record on December 15, 1983. Thus, at the close of the record in ER82-483, which was some seven months after the close of the record in ER82-616, the most recent cost information supported a rate of return on equity of 15.35%.

Judge Head in ER82-483 determined that he record supported a range of returns of 15% to 16% for MSS's return on equity. While concluding that staff's rate of return analysis was the best reasoned and supported analysis in the record, he reassessed staff's 15.35% recommendation in light of two post-record event: a decrease in MSU's average stock price and recent news articles indicating an increase in the perception of risk for electric utilities with nuclear plant construction. He concluded that when these two factors are taken into account, the return on equity should be set closer to the high end of the zone of reasonableness. Accordingly, he set the return at 15.75%.

Several parties in ER82-483 excepted to Judge Head's use of post-record data to raise the rate or return.[37] We,

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[37] MSE argued that the same post-record data should be used to update Judge Liebman's recommended rate of return in ER82-616. We

too, have general concerns about adjusting a rate of return based solely on certain isolated changes that factor into a DCF analysis. Although falling stock prices may be indicative of increased capital costs, we are reluctant to raise a rate of return based on a change in only one element of the DCF analysis. Furthermore, if we were to adjust the staff's DCF analysis to reflect post-record changes in stock prices, presumably we would also, if requested, have to adjust the analysis to reflect post-record changes in dividend payouts and expected growth rates, the other elements of the analysis. The consequence of making the adjustment would thus be that he results of a DCF analysis could be continuously litigated. Although this course might make the allowed rate of return somewhat more reflective of current conditions, we question whether the gain in doing so would out weight the "administrative necessity of closing the books at a time certain."[38]

In reference to the recent wave of highly publicized bad news for the nuclear power industry, the news articles relied on merely accentuate a fact already known and considered by the staff and the Commission for some time, i.e., that utilities building nuclear generating units generally face greater financial risk than other utilities. Additionally, we do not think it appropriate to modify a rate of return of a company based solely on news stories concerning other companies' nuclear construction problems.

Although we decline to adjust the record-supported rate of return based solely on news stories concerning the recent setbacks encountered in nuclear construction programs, or on the drop in MSU's stock prices, we note that since the close of both records, there has been a

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note, however, that to fully update that older record it is first necessary to consider the subsequent decreases in capital cost evidenced by the intervening ER82-483 record.

[38] *Jersey Central Power & Light Co. v. F.E.R.C.*, No. 82-2004, slip op. at 11 (D.C. Cir., Mar. 30, 1984).

deterioration in the financial condition of MSU. Standard and Poor's Corporation recently downgraded several debt issue ratings of the MSU operating companies.[39] Moody's Investor Service, Inc., also downgraded MSE's $300 million in first mortgage bonds from Ba-1 to Ba-2, and assigned a Ba-2 rating to its new issue of $100 million in first mortgage bonds.[40] This downgrading is a significant and concrete factor specific to MSU and its subsidiaries, and presumably reflects perceptions of increased risk resulting from the construction of Grand Gulf 1 and 2, as well as any other changes in rate of return indicia specific to MSU and its subsidiaries. It is a factor that did not exist at the time of either initial decision. Thus, based on *all* of the above considerations, particularly the recent downgradings, we believe that the allowed return should be somewhat higher than that recommended by Judge Head. We conclude that the rate of return in both dockets should be at the high end of the range of supportable returns established in ER82-483, since, as noted above, that docket contains an updated analysis of the methodology and data employed in ER82-616 (which rates have not yet gone into effect). We therefore adopt 16.00% as the appropriate allowed rate of return on equity for both dockets.

The Commission orders:[41]

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[39] *The Energy Daily*, Apr. 26, 1985, p. 4; *The Wall Street Journal* Apr. 26, 1985, p. 12.

[40] *The Wall Street Journal* May 16, 1985, p. 49.

[41] Several miscellaneous matters are addressed in the ordering paragraphs below. We identify them here, although we do believe that they require further explanation. Two issues presented in later dockets have been made subject to the outcome of Docket No. ER82-483 and should be treated in accordance with this opinion: (1) the MSS-1 O&M adder as applied in Docket No. ER83-66 (Letter order dated December 14, 1982); and (2) the return on equity to be applied in Docket No. ER84-283 (Letter order dated March 29, 1984). With respect to the UPSA at issue in ER82-616, a language change is being ordered so

Docket No. ER82-616-000

(A) The proposed settlement agreement filed in this docket and Docket No. ER82-483-000, on January 4, 1985, as revised on February 5, 1985, is rejected. Any motions filed in these dockets not acted on herein, or previously acted on, are denied.

(B) The initial decision issued in this docket on February 3, 1984, is affirmed to the extent not modified in this opinion.

(C) MSE shall revise the Grand Gulf Unit No. 1 entitlement percentages in Section 1.2 of the UPSA as follows:

AP&L 36%

LP&L 14%

MP&L 33%

NOPSI 17%

(D) MSE shall remove from Section 1.2 of the UPSA the percentage allotments for Grand Gulf Unit No. 2, without prejudice to a subsequent filing.

(E) MSE shall delete Section 14 form the UPSA, which section provides that AP&L will have no rights or obligations under the UPSA.

(F) MSE shall amend Schedule B, Page 2, Cost Rate 'C', and Section 1.3 of the UPSA to reflect the rate of return on equity adopted herein.

(G) MSE shall revise Section 1.3 of the UPSA to refer to the Uniform System of Accounts prescribed for "Major" utilities rather than "Class A and B" utilities.

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that Section 1.3 will properly refer to the Uniform System of Accounts for "Major" utilities rather than "Class A and B" utilities, consistent with our Order No. 390, *FERC Statutes and Regulations* ¶30,586, issued August 3, 1984.

(H) MSE may use the units of production depreciation method for one year. Conventional straight-line depreciation shall be used for the remainder of the service life of Grand Gulf Unit No. 1.

(I) The annual decommissioning amount allowed in rates shall be in accordance with this order, which is 90% of the amount approved by the judge, or $1,113,118.

(J) MSE shall file with the Commission an algebraic tax formula and an accounting treatment for tax items for derivation of income taxes.

(K) MSE may record appropriate entries in Account 404 (Amortization of Limited Term Electric Plant) without prior commission approval.

(L) MSE shall file amendments to the UPSA to reflect the changes required in these ordering paragraphs, as well as any other amendments necessary to reflect the findings and conclusions in this opinion, within thirty (30) days of the date of this opinion.

Docket No. ER82-483-000

(M) The initial decision issued in this docket on February 4, 1985, is reversed as to the issue of Grand Gulf cost allocation. It is affirmed on all other issues, except as modified in this opinion.

(N) MSS shall amend the following 1982 System Agreement service schedules to reflect the rate of return on equity adopted herein:

MSS-1—Reserve Equalization—Section 10.06

MSS-2—Transmission Equalization—Section 20.06

MSS-4—Unit Power Sale—Section 40.05

(O) Service Schedule MSS-1, Section 10.02(c) shall be modified to provide a firm power purchase capacity credit

based on supplier's actual reserves rather than imputed reserves.

(P) MSE shall file amendments to the 1982 System Agreement to reflect the changes required in these ordering paragraphs, as well as any other amendments necessary to reflect the findings and conclusions in this opinion, within thirty (30) days of the date of this opinion.

(Q) Within thirty (30) days of the Commission's approval of the compliance filings ordered herein, the companies shall refund, with interest, any amounts collected in excess of those allowed pursuant to this opinion. Within fifteen (15) days thereafter, they shall file a report showing the computation of the refunds and interest paid. A copy of the refund report shall also be sent to all State regulatory agencies in States with customer affected by this order.

(R) Pursuant to a letter order dated December 14, 1982, the MSS-1 Operation and Maintenance Expense Adder modification in Docket No. ER83-66-000 is subject to the outcome of this docket.

(S) Pursuant to a letter order dated March 29, 1984, the Docket No. ER84-283-000 rate of return on equity modification from 18% to 16% is subject to the outcome of this docket.

(T) The motions for oral argument filed on March 26, 1985, by the LPSC, CNO, OCC and Georgia Gulf Corporation, and Jefferson Parish, Louisiana, are denied.

(U) The motion for a limited reopening of the record in Docket No. ER82-483, filed by OCC on April 4, 1985, is denied.[42]

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[42] In support of its motion, OCC stated that Judge Head had relied only on the "first-hand, personal knowledge" of one witness in making his finding that there is autonomy on the part of the MSU operating companies. OCC sought to reopen the record to introduce other "first-hand, personal knowledge" contradicting that relied on by Judge Head. OCC's motion is moot given our finding herein that the record does not support Judge Head's autonomy finding.

(V) The motion to lodge an APSC order, filed by the LPSC, OCC and Georgia Gulf Corporation on May 28, 1985, is denied.[43]

Commissioner Richard's separate statement is attached.

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[43] This motion sought to lodge on April 3, 1985 order of the APSC in an AP&L retail rate case. The movants sought to bring to the Commission's attention portions of the order in which the APSC discussed the relationship between MSS and MP&L, and in which the APSC recognized that the amount of AP&L White Bluff capacity purchased by LP&L and NOPSI was an offset to the Arkansas retail cost of service. This motion is now moot given our findings concerning the integrated nature of the MSU System and the interrelationship of the MSU subsidiaries.

Statement of Commissioner Oliver G. Richard III in Response to "Motion Requesting Recusal" in Docket Nos. ER82-483-000, Middle South Services, Inc.; and ER82-616-000, Middle South Energy, Inc.

Arkansas Power & Light Company (AP&L), the Attorney General of the State of Arkansas, the Attorney General of the State of Mississippi and the Cities of Conway and West Memphis, Arkansas have requested that I recuse myself from participation in the *Middle South* proceedings.[1] I find no merit in the motion, and decline to recuse myself.

The moving parties maintain that my past employment by Senator J. Bennett Johnston of Louisiana, who, along with the full Louisiana Congressional delegation, has intervened in Docket No. ER82-616, creates the appearance of bias which denies them a fair hearing. I disagree.

Between 1977 and 1981 I worked as a legislative assistant to Senator Johnston. In that capacity, I advised him on a wide variety of issues, including energy issues. I also assisted in drafting legislation that the Commission now implements. However, my employment with the Senator ended in August 1981, almost one year before the *Middle South* proceedings began. I had no prior contact with the facts or legal issues involved in *Middle South* before joining the Commission in 1982.

I fully agree that all parties to a Commission proceeding are entitled to a fair hearing before an impartial decisionmaker. There are no facts or circumstances arising from my prior employment or relationship with Senator Johnston that impair my impartiality. My employment with the Senator ended three years ago; I have had no prior

[1] Responses in opposition to the motion have been filed by the Louisiana Public Service Commission; Louisiana Power & Light Company; New Orleans Public Service Company, Inc., the City of New Orleans, Louisiana and the Occidental Chemical Corporation.

contact with *Middle South;* and I have expressed no opinion about the merits of the proceedings.

Furthermore, contrary to the claim of the Cities of Conway and West Memphis, I have had no business association with "residents of Louisiana" since joining the Commission.[2]

The nature of Senator Johnston's involvement in *Middle South* further precludes an "appearance of impropriety" based on my relationship with him. He is participating as a public official pursuing policy goals rather than as a private individual with an economic stake in the outcome of these proceedings. As a formal intervenor before the Commission, the Senator, along with the entire Louisiana Congressional delegation, will place his opinions on the record, subject to rebuttal by any other party. Thus, contrary to AP&L's assertion, the Senator's intervention bears no resemblance to the sort of extra-record questioning of decisionmakers by Congressmen that has sometimes been held to impair the integrity of the decisionmaking process. My own decision in *Middle South* will be based solely on the evidence established in the record.

I have also considered the cost of recusal. Recusal is not a matter to be undertaken lightly. Just as a decision-

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[2] The Cities contend that my "subsequent business association with residents of Louisiana whose interests are now contrary to those of the Arkansas parties in these cases create[s] an appearance of impropriety." I do not know what they mean. I have no financial ties to any "residents of Louisiana," including my former law firm of Hayes, Durio & Richard. My former firm is not involved in the *Middle South* proceedings. If the Cities are alleging that as ratepayers my former partners have interests adverse to the residents of Arkansas, then they have not raised grounds for recusal. Indeed, they're not even ratepayers. The possibility that a proceeding will affect the future utility bills of the decisionmaker *himself* as a member of the general public does not create a financial conflict of interest that warrants recusal. In Re Natural Gas Antitrust Litigation, 620 F.2d 794, 796-97 (10th Cir. 1980). In Re Virginia Electric and Power Co., 539 F.2d 357, 368 (4th Cir. 1976).

maker has a duty to recuse himself in the proper circumstances, he has a concomitant obligation not to recuse himself without a valid reason. *Simonson v. General Motors Corporation,* 425 F. Supp. 574 (D.C. Pa. 1976). This consideration is even truer for regulators than for judges. A Commissioner who withdraws from a case cannot be replaced, as a judge can.[3] Since a Commissioner has a policymaking as well as a judicial role, his policy insights and outlook are lost to the collective decisionmaking process of the agency, if he fails to participate. I will give full and fair consideration to the merits of these proceedings, and, by any objective standard, there is no reasonable basis for concern about bias. Accordingly, I have an obligation to participate in these important matters, and thus deny the motions by the aforementioned parties.

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[3] By way of analogy, Justice Rehnquist has pointed to the fact that Supreme Court Justices cannot be replaced as one reason they should be more reluctant than lower court judges to disqualify themselves. Laird v. Tatum, 409 U.S. 824 (1972), memorandum of Rehnquist, J.

APPENDIX D

CITED AS "30 FERC ¶ . . . ."

[¶63,030]

Middle South Services, Inc., Docket No. ER82-483-000

Initial Decision

(Issued February 4, 1985)

Appearances

Richard M. Merriman, Robert S. Waters, Lisa H. Powell, William D. Meriwether, Jr., and *Floyd L. Norton, IV* for Middle South Services, Incorporated

Steve L. Riggs, Jerry D. Jackson, Robert J. Glasser and *Carl D. Hobelman* for Arkansas Power & Light Company

Andrew P. Carter, Eugene Taggart and *Willie J. Nunnery* for Louisiana Power & Light Company and New Orleans Public Service, Inc.

George F. Bruder, James K. Child, Jr. and *Henderson S. Hall, Jr.* for Mississippi Power & Light Company, Louisiana Power & Light Company, and New Orleans Public Service, Inc.

Robert Wood, N. M. Norton, Jr., Wallace L. Duncan, J. Cathy Lichtenberg and *Janice L. Lower* for Arkansas Public Service Commission

Steve Clark, Garry W. Wann, Robert H. Wood, Jr. and *Roger Giles* for the Arkansas Attorney General

Richard M. Smith for the Congressional Delegations of the States of Arkansas and Missouri

Zachary D. Wilson for the Cities of Benton, North Little Rock, Osceola and Prescott, Arkansas and Farmers' Electric Cooperative Corporation

A. Hewitt Rose, Charles F. Wheatley, Jr., Michael J. Thompson and *Peter A. Goldsmith* for Conway and West Memphis, Arkansas

Michael E. Fontham, Marshall B. Brinkley and Paul L. Zimmering, Jr. for Louisiana Public Service Commission

David B. Robinson and Mariano G. Hinojosa for the Louisiana Attorney General

David B. Robinson for Louisiana Congressional Delegation

Honorable W. J. (Billy) Tauzin for W.J. Tauzin

Clinton Vince, Glenn Ortman, Paul Nordstrom and *Greg Ottinger* for the City of New Orleans

Champ Terney, Hiram C. Eastland, Jr., Bennett Smith, Glen Hays, Donna Allday, Edwin Lloyd Pittman and *Jay Stewart* for Mississippi Public Service Commission

John L. Maxey, II for Mississippi Attorney General

Honorable Wayne Dowdy and *Webb Franklin* for Wayne Dowdy and Webb Franklin

Martin C. Rothfelder for the Missouri Public Service Commission

James M. Fisher and *Richard W. French* for the Missouri Office of the Public Counsel

James B. Selna, David T. Beddow and *Donald T. Bliss* for Amax

John B. O'Sullivan, Robert F. Shapiro and *Bernays T. Barclay* for International Paper Company

Earl H. O'Donnell and *Robert R. Morrow* for Occidental Chemical Corporation and Georgia Pacific Corporation

Paul H. Keck and *Brian R. Gish* for Mississippi Industries

Alfred J. Cheplin, Jr. for Mississippi Legal Services Coalition

Bonnie S. Blair and *Robert McDiarmid* for Municipal Energy Agency of Mississippi

John Nassikas, James L. Trump, J. Mark Davis, Alston Jennings, Jr., and *Kenneth A. Barry* for the Arkansas Industries

William A. Chesnutt and *Henry R. MacNicholas* for Union Carbide Corporation

Thomas L. Blackburn and *Charles Reusch* for the Staff of the Federal Energy Regulatory Commission

Daniel M. Head, Administrative Law Judge.

Table of Contents

I. Procedural History

On April 30, 1982, Middle South Services, Inc. (MSS) filed with the Commission a revised agreement among itself, Arkansas Power & Light Company (AP&L), Louisiana Power & Light Company (LP&L), Mississippi Power and Light Company (MP&L) and New Orleans Public Service, Inc. (NOPSI). This agreement, dated April 23, 1982 (hereinafter referred to as the 1982 System Agreement) is designed to govern transactions among the aforementioned parties, all of whom are subsidiaries of Middle South Util-

ities, Inc. (MSU), a registered public utility holding company. MSS is the service company subsidiary of MSU, while the other four parties to the 1982 System Agreement are operating utilities which furnish electric service at retail and wholesale in the state of Arkansas, Louisiana, Mississippi and Missouri. Generation and transmission facilities of AP&L, LP&L, MP&L and NOPSI are electrically interconnected and operated on a coordinated basis to form the Middle South system.

By order issued July 29, 1982, the Federal Energy Regulatory Commission (FERC or Commission) accepted the 1982 System Agreement for filing, suspended it for five months to become effective January 1, 1983, and set for hearing the justfulness and reasonableness of the agreement. The Commission acted pursuant to its authority under Section 402(a) of the Department of Energy Organization Act, 42 U.S.C. §7172 (Supp. V 1981), and under Sections 205 and 206 of the Federal Power Act (FPA), 16 U.S.C. §§824(d) and (e). Order Accepting for Filing and Suspending Rates, Granting and Denying Intervention, and Establishing Hearing Procedures, 20 FERC ¶61,119 (1982).

In addition, on September 2, 1982, the Commission severed the issue of the lawfulness of the cogeneration provisions of the 1982 System Agreement from this proceeding and consolidated it with two other Middle South proceedings, Docket Nos. ER81-428-000 and EL81-12-000.

October 14, 1982, the Louisiana Public Service Commission (LPSC), the Mississippi Public Service Commission (MPSC), the State of Mississippi and the Mississippi Legal Services Coalition jointly moved for consolidation of this cause with Middle South Energy, Inc., Docket No. ER82-616-000 (the Grand Gulf proceeding). The Grand Gulf proceeding involves a proposed unit power sales agreement under which Middle South Energy, Inc. (MSE), another wholly owned subsidiary of MSU, plans to sell the capacity

and energy of its share of the Grand Gulf nuclear generating station in Mississippi, to LP&L, MP&L and NOPSI, after the Grand Gulf facility begins commercial operation. On November 12, 1982, the Chief Administrative Law Judge denied the motion for consolidation, *Middle South Services, Inc.*, 21 FERC ¶63,039 (1982).

During the course of this proceeding, both before and after the evidentiary hearing, numerous parties sought to intervene. All petitions to intervene were granted, either by the Commission or by the Presiding Judge, except for one by Citizens for Safe Energy, which was denied by order of the Presiding Judge dated September 20, 1982. As a result, the following parties have been granted party intervenor status in this cause: the four MSU operating companies, AP&L, LP&L, MP&L and NOPSI; the Arkansas Public Service Company (APSC); the Attorney General of Arkansas; the Arkansas-Missouri Congressional Delegations; the Cities of Benton, North Little Rock, Osceola and Prescott, Arkansas, and the Farmers Electric Cooperative Corporation (Benton); the Cities of Conway and West Memphis, Arkansas (Conway); the Louisiana Public Service Commission (LPSC), the Attorney General of Louisiana; the Louisiana Congressional Delegation; Representative W. J. Tauzin (La.); the City of Lafayette, Louisiana; the City of New Orleans Louisiana (CNO); the Mississippi Public Service Commission (MPSC); the Attorney General of Mississippi; Representatives Wayne Dowdy and Webb Franklin (Miss.); the Missouri Public Service Commission (MoPSC); the Public Counsel of the State of Missouri; Amax; Georgia-Pacific Corporation; International Paper Company; Occidental Chemical Company (OCC); Mississippi Industries; Mississippi Legal Service Coalition; the Municipal Energy Agency of Mississippi; Reynolds Metal Company, Richland Foods, Weyerhauser Company and Associated Industries of Arkansas (Arkansas Industries); and Union Carbide Corporation.

MSS filed its direct testimony in October 1982. Rebuttal testimony was submitted in April 1983 by the Staff, LPSC, CNO, MPSC and the Arkansas Attorney General. Cross-rebuttal testimony was filed in July 1983 by Arkansas Industries, the Arkansas Attorney General, APSC and MoPSC. MSS filed its rebuttal testimony in August 1983. Surrebuttal testimony was filed by the Staff, LPSC, CNO and OCC in September 1983. Except for a portion of OCC's surrebuttal testimony, which was admitted on October 26, 1983 (Tr. 2375), the surrebuttal testimony was rejected by the Presiding Judge in rulings from the bench during the evidentiary hearing session of October 11, 1983 (Tr. 1259-1384).

An initial prehearing conference was held August 31, 1982, which resulted in establishment of the procedural schedule in this cause. A second prehearing conference was held September 22, 1983, to delineate the issues to be tried, to determine the order of presentation of the cases and scheduling of witnesses, to discuss procedures to be employed during the hearing and to identify the exhibits to be presented by the parties (Tr. 59). The evidentiary hearing began on September 29, 1983 and concluded on December 15, 1983, after 45 hearing days. The record consists of a transcript of 7,072 pages in 48 volumes and 487 exhibits, including three stipulations relating to an AP&L coal contract and to Grand Gulf I costs. These stipulations were admitted on April 12, 1984 as posthearing exhibits. Initial briefs were filed by the parties on April 16, 1984 and reply briefs on June 4, 1984. Also, after the hearing, official notice was taken of five documents, two in an order issued July 20, 1984 and three in an order issued January 24, 1985.

In addition, on February 15, 1984, MSS proposed a change to the 1982 System Agreement which reduced the return on common equity component of the pricing formulas in the service schedules from 18% to 16%. MSS requested an effective date of January 1, 1983 for the

change and authorization for the MSU operating companies to make appropriate refunds. By letter order dated March 29, 1984, the Director of the Division of Electric Rate Regulation accepted the change from 18% to 16% as of January 1, 1983, and authorized appropriate refunds. In addition, the rate revisions were made subject to refund pending the outcome of this proceeding. The Director denied a CNO motion to consolidate the docket involving the rate of return reduction (Docket No. ER84-283-000) with the current docket. Thereafter, Docket No. ER84-283-000 was terminated.

MSS, on February 2, 1984, filed a "Notice of Separate Positions of Arkansas Power Light Company, Mississippi Power & Light Company, Louisiana Power & Light Company and New Orleans Public Service, Inc." In this notice, MSS advised that the MSU operating companies would take different positions on the production cost allocation issue. LP&L, MP&L and NOPSI would espouse a method of allocation designed to bring about a form of equalization of production costs among the operating companies while AP&L would adopt the position advanced by MSS at the evidentiary hearing. Prior to this time, MSS had acted as agent for all the operating companies. With this change, MSS discontinued representation of the operating companies on the issue of production cost allocation, although it continues to represent the operating companies on the other issues in the case. On February 14 and 16, 1984, respectively, LP&L and NOPSI jointly and MP&L individually filed their statements of separate positions.

Moreover, LP&L, MP&L and NOPSI on March 2, 1984 filed an offer of settlement based upon the cost equalization proposal presented by LPSC. In light of the change of position of the operating companies and because of the active posthearing pleading by the parties, a posthearing conference was convened on March 28, 1984. Most of the then outstanding motions were disposed of at that prehearing conference.

In addition, by order of March 29, 1984, the Chief Administrative Law Judge denied a motion filed by the Staff on March 9, 1984, for appointment of a settlement judge. Also, the Presiding Judge, by order issued April 20, 1984 [27 FERC ¶63,043], refused to certify the March 2, 1984 LP&L, MP&L and NOPSI offer of settlement, because of procedural impediments and the presence of genuine issues of material fact.

This initial decision will address all issues raised by the Commission's July 29, 1982 order setting this cause for hearing and all pertinent issues raised by the parties during the course of this proceeding. Any arguments in the initial and reply briefs not specifically addressed are hereby rejected as not supported by the Presiding Judge's evaluation of the evidence or as not being of sufficient persuasiveness to warrant comment. Furthermore, any proposed finding or conclusion submitted in the parties' briefs, which finding or conclusion is not incorporated directly or inferentially into this initial decision, is herewith rejected as being unsupportable in law or fact, or as being unnecessary to the rendering of the initial decision.

II. Overview

The current litigation can, for evaluation purposes, be broken down into three distinct areas. By far the issue of most importance is production cost allocation. There is also a controversy on rate of return. And, in a third area, there are miscellaneous issues that can be disposed of in a separate section of the decision. In resolving these issues, rate of return will be dealt with first, followed by the miscellaneous issues, and then the production cost allocation issue.

The dispute regarding rate of return matters, on the return on equity. In light of MSS' reduction of its requested return on equity from 18% to 16%, the controversy on rate of return has been greatly reduced.

Likewise, the miscellaneous issues present only minor stumbling blocks to resolution of this litigation. These miscellaneous issues cover the following six areas: LPSC's request that periodic review conditions be attached to the cost of service formula rates approved in the 1982 System Agreement; CNO's request that transmission investment be reclassified; CNO's request that intermediate generation units be redefined; CNO's request for alteration of the handling of administrative and general expenses under the 1982 System Agreement; CNO's request that the adder in the Service Schedule MSS-3 be rejected; and CNO's request that the adder in Service Schedule MSS-1 be rejected. While certain of these miscellaneous issues might become moot depending upon the outcome of the production cost allocation issue, they nonetheless will be individually treated, since resolution thereof is necessary in the event that a different result on the production cost allocation issue is ordered upon Commission review of this initial decision.

Finally, the major issue in the case, production cost allocation, will be reviewed and resolved. In this regard, there are three major opposing views that pit the various jurisdictions against each other. Originally, and during the course of the evidentiary hearing, MSS and the four MSU operating companies (AP&L, LP&L, NP&L and NOPSI) took the position that the 1982 System Agreement should be adopted as filed, which would result only in reserves being equalized based upon the cost of the long ("long" will be later defined) companies' intermediate (oil and gas fired) units. This position was supported by the Arkansas interests in this case.

The second major position, advanced in different proposals by LPSC, the Commission Staff and CNO, is that the 1982 System Agreement should be revised to provide for production cost equalization among the four operating companies. The equalization proposals are substantially

similar and all would require a major revision of the 1982 System Agreement.

A third position is sponsored by MPSC, who would have the 1982 System Agreement rejected. In its place, MPSC would reestablish the 1973 System Agreement, with its participation unit concept. Under the participation unit procedure, the capacity costs of the last production facility put on line by a long company is paid for by the short companies to the extent that they are short. the short companies are also entitled to a proportionate share of the energy from the participation unit but must pay the energy costs therefor. MPSC would make MSE, the owner of the Grand Gulf nuclear facility, a party to the System Agreement, and Grand Gulf would become a participation unit.

The factual backdrop of these proposals is that AP&L was able, during the 1970's and early 1980's, to bring on line two nuclear generating facilities and two coal facilities at a cost of about $500 per kilowatt (kw). During the same time frame, LP&L was unable to construct and begin to operate the Waterford 3 nuclear facility and MSE was unable to construct and bring on line the Grand Gulf Unit No. 1 nuclear facility. These factors, coupled with a radical decrease in the demand for electricity and the failure of competing oil prices to rise as expected, have left the operating companies of the MSU system with large reserve capacity which will increase when the Waterford 3 and Grand Gulf units become operational. The essential question presented is how to deal equitably with the very large costs of Waterford 3 and Grand Gulf Unit No. 1. These 1100 plus megawatt facilities are expected to commence operation in the near future with capacity costs of approximately three billion dollars apiece, resulting in a cost per kw of over $2500 (MSS Ex. 67; Tr. 4125-26; MSU SEC Form U-1, pp. 12, 15, May 31, 1984). When these two plants come on line, they will represent over 70% of the 1985 expense for production facilities on the entire Middle South system but they will only generate about

13% of the electricity to be used on the system. (CNO Ex. 4, p. 24; Tr. 3489, 3552-54). The 70% plus figure is reached when the current costs for Waterford 3 and Grand Gulf 1 are considered in relation of Table 3 on page 24 of CNO Exhibit 4. In light of the above, the real matter at issue is what portion of these expensive new plants should each jurisdiction (Arkansas-Missouri, Louisiana, Mississippi and New Orleans) pay?

In evaluating this complex production cost allocation issue, the history of system operations must be reviewed in appropriate depth and conflicts concerning State and Federal ratemaking authority must be analyzed. Moreover, the impact of the production cost allocation proposals on the various jurisdictions must be scrutinized and consideration given to authorities pertinent to pooling arrangements. Disposition of the issues outlined in this overview will lead to determination of whether the 1982 System Agreement is just and reasonable and should be approved in whole and part, or whether any modification to the Agreement are needed. Before reaching the specific matters in controversy, however, it is warranted to analyze pertinent portions of the 1982 System Agreement and its predecessors.

III. The System Agreement

The 1982 System Agreement, which was admitted into evidence as MSS Exhibit 2, constitutes an updating of prior agreements governing the operating companies' pooling arrangements. From 1973 until January 1, 1983, when the 1982 System Agreement went into effect, transactions among the operating companies were controlled by the "1973 System Agreement" (APSC Ex. 25), which was approved by the Federal Power Commission in *Middle South Services, Inc.*, 49 FPC 1472 (1973). The 1973 Agreement was modified and updated several times and was approved with certain modifications in *Middle South Services, Inc.*, 16 FERC ¶61,101 (1981), *aff'd sub nom. Louisiana Public*

Service Commission v. F.E.R.C., 688 F.2d 357 (5th Cir. 1982), *cert. denied*, 460 U. S. 1082 (1983). The predecessor of the 1973 System Agreement was the 1951 System Agreement (MSS Ex. 18).

In summary, the 1982 System Agreement has six major articles and six service schedules. The Articles are: (I) Term of Agreement; (II) Definitions; (III) Objectives; (IV) Obligations; (V) Composition and Duties of the Operating Committee; and (VI) System Operations Center. The service schedules are: MSS-1—Reserve Equalization; MSS-2—Transmission Equalization; MSS-3—Exchange of Electrical Energy among the Companies; MSS-4—Unit Power Purchase; MSS-5—Distribution of Revenue from Sales Made for the Joint Account of All the Companies; and MSS-6—Distribution of Operating Expenses of System Operations Center. Most of these provisions are not at issue and, as discussed *supra*, the main controversy in this cause focuses on whether the agreement should be revised to provide for production cost equalization, the adoption of which would have a profound effect on the overall agreement.

To frame this issue properly, it is warranted to consider in pertinent part the objectives contained in Article III of the 1982 System Agreement. Section 301 of Article III sets out:

> 3.01. The purpose of this Agreement is to provide the contractual basis for the continued planning, construction, and operation of the electric generation, transmission and other facilities of the Companies in such a manner as to achieve economies consistent with the highest practicable reliability of service, subject to financial considerations, reasonable utilization of natural resources and minimization of the effect upon the environment. This Agreement also provides a basis for equalizing among the Companies any imbalance of cost associated with the construction, ownership and

operation of such facilities as are used for the mutual benefit of all the companies.

Article III also provides *inter alia:* for planning, construction and operation of both power supply and related facilities on a coordinated basis (Section 3.02); for moving toward a new fuel base of coal and nuclear to minimize costs and reduce dependence on gas and oil (Section 3.03); for a long-term goal of each company having a proportionate share of coal and nuclear units available to serve its customers, either by ownership or purchase (Section 3.05); for centralized dispatching of energy supply to foster reliability of service and economy of operation (Section 3.07); and for joint planning on a system-wide basis for construction and operation of major facilities to achieve economies of scale associated with construction and operation of larger generating units and higher voltage lines (Section 3.08).

Moreover, among the obligations set out in Section 4.01 of Article IV of the 1982 System Agreement, there is a requirement that each company normally own, or have available to it under contract, generating capability and other facilities necessary to supply all the requirements of its own customers. This same section further provides that the Operating Committee determine a generation addition plan based upon 10-year estimates submitted by the companies, to provide capacity for the projected system load and furnish reliable service at the lowest cost. It also states that any capability in excess of the Capability Responsibility of a company that may exist in the system of one or more companies as a result of construction pursuant to the generation addition plan, shall be equalized among the companies in accordance with the provisions of the applicable Service Schedule.

Under Article II of the 1982 System Agreement, the Capability Responsibility referred to in the above paragraph is defined as the product of the System Capability

multiplied by the Responsibility Ratio for each company (Section 2.19). System Capability is the arithmetical sum in megawatts (MW) of the individual Company Capabilities (Section 2.15), and Responsibility Ratio is the ratio obtained by dividing the individual Company Load Responsibility by the System Load Responsibility (Section 2.18), which is the arithmetical sum in MW of the individual Company Load Responsibilities (Section 2.17). The Company Load Responsibility for each company is determined by averaging the sum of the company's twelve monthly hourly loads coincident with the system's monthly peak hour load for the period ended with the current month; it is measured in MW (Section 2.16).

To simplify and put the above definition into practice, an individual company's Capability Responsibility can be more readily understood from the following example. If Company A's load is 20% of the total system load, its responsibility for total system capacity would also be 20%. If total system capacity were 10,000 MW then Company A's Capability Responsibility would be 2,000 MW. If Company A had either owned or purchased capacity greater than 2,000 MW, it would be considered long and entitled to receive equalization payments from companies which would be short. On the other hand, if Company A had less than 2,000 MW of capacity, it would be considered short and have to make equalization payments to companies which are long.

The equalization payment described above and provided for in Article IV of the 1982 System Agreement, would be made under Service Schedule MSS-1 governing reserve equalization (Section 4.01). Under that Service Schedule, the short companies will pay the long companies based upon the costs of the long companies' intermediate generation units, which are defined in Article II of the 1982 System Agreement as generating units whose fuel supply is gas or oil (Section 2.09).

It should be noted at this juncture that the capacity equalization provisions in the 1982 System Agreement gives each kW of capacity equal weight, with no differentiation based upon the cost per kW of capacity (Service Schedule MSS-1). Moreover, the fact that a company is considered short under the 1982 System Agreement methodology, does not mean necessarily that that company, standing alone, lacks adequate generating capacity to meet its customers' requirements. Being short only means that the company has less capacity than its proportionate system load responsibility. For example, posit that the total system load is 10,000 MW and that Company B has a load of 4,000 MW making the Company Load Responsibility 40% for Company B. Then, if the total system capacity was 16,000 MW, Company B's Capacity Responsibility would be 6,400 MW (40% of 16,000). Assuming further that Company B had owned and purchased capacity of 5,000 MW, it would have 1000 MW more than its load but would nonetheless be 1,400 MW short under the 1982 System Agreement and required to make reserve equalization payments.

Under the 1951 System Agreement, the capacity equalization payments made by a short company to a long company were based upon a fixed dollar amount per kW and there was no entitlement to energy associated with the capacity payment (MSS Ex. 18). This changed under the 1973 System Agreement, which provided for reserve capacity equalization based upon a "participation unit" concept. Under this approach, equalization payments were based upon the capacity and energy costs of the latest unit constructed by the long company, but the short company was entitled to its proportionate share of the participation unit, including a proportionate share of energy generated from that unit (APSC Ex. 25). In the 1982 System Agreement, however, the short companies do not receive energy from the intermediate oil and gas-fired units upon which the equalization payments are based but instead the short companies are entitled to purchase energy

at the exchange energy rate under Service Schedule MSS-3, which is the lowest cost energy available from the pool. Generally, therefore, exchange energy is less expensive than that produced by the oil and gas-fired generating units.

Service Schedule MSS-3 is designed to permit economic dispatching. Under Service Schedule MSS-3, all capacity is controlled by the system operator and dispatched to obtain the lowest practical cost within ordinary operating constraints. For billing purposes, energy from this capacity and from purchases is allocated from the lowest cost sources, first to the loads of the companies owning those sources and secondly to the pool. Therefore, the company or companies supplying energy to the pool will be reimbursed for the cost of fuel used, plus an adder reflecting incremental operation and maintenance costs. (MSS Ex. 1, p. 14.)

Further, Service Schedule MSS-4 was added to the 1982 System Agreement to enable the companies to make unit power purchases when mutually agreeable. Service Schedule MSS-4 allows a company to purchase capacity and associated energy from a designated generating unit of another company for any mutually agreed upon period of time. This sale of energy is priced at the price of the cost of fuel burned in accordance with Section 30.03(a) of Service Schedule MSS-3 and the sale of capacity is priced in accordance with Sections 40.03 - 40.05 of Service Schedule MSS-4. (MSS Ex. 1, p. 26.)

As can be seen from the above description of the 1982 System Agreement, it is designed to cover pooling transactions among the MSU operating companies. With this background, attention can now be focused on the three areas of controversy: rate of return, miscellaneous issues and production cost allocation. They will be dealt with *seriatim,* beginning with the rate of return controversy.

IV. Rate of Return

A. Return on Equity

Regarding rate of return, the major issue involves the appropriate return on equity allowance for Service Schedules MSS-1, MSS-2 and MSS-4 of the 1982 System Agreement. MSS initially proposed an allowance of 18% but, as mentioned in Section 1, *supra,* prior to the hearing modified its proposal to request an allowance of 16%. MSS submits that the record herein supports its proposal and it also relies on the initial decision in *Middle South Energy, Inc.*, 26 FERC ¶63,044 (1984), in which a 16.04% return on equity for MSE's Unit Power Sales Agreement was adopted. (MSS Initial Br., p. 17.) Staff presented a forward-looking discounted cash flow (DCF) analysis in advocating a 15.35% return on equity (Staff Initial Br., pp. 4-5). The Arkansas Attorney General also used a DCF analysis to conclude that the current allowed return of 14.0% is fair and reasonable (Arkansas Attorney General Initial Br., pp. 43-48). CNO's DCF studies purportedly demonstrate that MSS is entitled to a maximum return on common equity of 15.46% (CNO Initial Br., p. 58). LPSC prefers that FERC use the weighted average cost of equity allowed the operating companies in the various jurisdictions they serve. Alternatively, LPSC urges use of a traditional DCF analysis with a cost of equity of 15%. (LPSC Initial Br., pp. 80-81.)

The positions of each of these parties, where the recommended return on common equity ranges from a low of 14% to a high of 16%, is developed more fully as follows.

1. MSS Position

MSS advocates using an approach which is based on current market conditions and which looks at dividend yields and price-earnings ratios as representative of investors' opinions with regard to MSU common stock (MSS

Ex. 13, p. 13). This method, which MSS labels as a variant of the DCF approach, involves determining the present value of cash flow investors expect to receive from purchasing MSU common stock. These cash flows would include dividends received during the holding period as well as proceeds from the sale of the stock at the end of that period. (*Id.* at 13-14). The overall cost recommendation is equal to the weighted average cost of (1) MSU's retained earnings and (2) MSU's new issues of common stock (*id.* at 27).

Application of the present value concept required MSS to estimate for future years the earnings per share, dividends per share and the price-earnings ratio for MSU. MSS' usage of the cost of common equity of MSU as the cost of common equity for each of the operating companies is in agreement with the approaches used by other parties in this docket. For estimating earnings per share, MSS turned to published forecasts of financial services and brokerage firms to determine its 1982 and 1983 estimates of $2.33 and $2.55, respectively. The growth for earnings per share after 1983 is estimated by the company as 3.5%, based principally on a review of MSU historical data for the past 10 years and culminating with the expectations that 3.5% is the appropriate growth rate. MSS then projects comparable dividend per share growth estimates at a level consistent with a 70% payout ratio. (*Id.* at 15-20.) By incorporating the above growth factors and payout ratio, and a stable price-earnings scenario and then a rising price earnings scenario, with a 12 month average price of MSU stock of $13.50 per share, MSS calculates a cost of retained earnings ranging between 16.2% and 17.0% (*id.* at 21-23). The cost percentage advocated by MSS was decreased in rebuttal testimony and again at the hearing because the average price of MSU stock for the latest 12 month period increased to $15.38 per share (MSS Ex. 15, pp. 1-2; Tr. 432). The market price of MSU common stock and the assumptions regarding the future price-earnings

ratio of the stock (including emphasis on the rising price-earning ratio scenario) are important variables in MSS' method of calculating the cost of retained earnings for MSU (MSS Ex. 13, pp. 20-22; Tr. 432-33).

Additionally, MSS' position relies on the development of the cost of new issues of common equity by MSU on the basis of a present value approach. It is explained that the cost of new issues is higher than the cost of retained earnings because: (1) the net proceeds from new issues will be less than the pre-issue market price by at least three to five percent; and (2) the market price, even before correcting for the adjustment in (1), is not equal to book value. (MSS Ex. 13, pp. 22-23.)

MSS identifies various fees and downward market pressures resulting from the sale of additional shares as the reasons for the five percent adjustment to the equity cost for new issues of MSU common stock (*id.* at 26). Using a constant growth model of dividend yield plus growth rate where assumptions were made regarding price and earnings values, MSS quantifies the adjustment necessary to achieve a market-to-book ratio of 1. Considering these two adjustments, the cost of new issues of common equity becomes 18.8%. (*Id.* at 23, 25-27.) MSS weights the 18.8% cost of new issues of common equity at 50% and weights the 16.2% cost of retained earnings at 50%, to derive an overall cost of common equity to MSU of 17.5%. Consideration of expectations for an increase in the price-earnings ratio as the market price moves toward book value, results in MSS' original 18% return on equity. (*Id.* at 27.) However, as previously discussed, the changing market value of MSU's stock price caused MSS ultimately to lower its recommendation for an overall return on equity allowance to 16% (Tr. 471-72).

In accordance with MSS' position that 16.0% is the appropriate return for the operating companies, on February 15, 1984, MSS filed in Docket No. ER84-283-000 a pro-

posed change to the 1982 System Agreement to reduce the rate of return on common equity from 18.0% to 16.0%. As discussed in Section I, *supra*, the Director of the Division of Electric Rate Regulation, by letter order dated March 29, 1984, accepted the change to 16.0% effective January 1, 1983, authorized appropriate refunds, made the rate revision subject to refund pending the outcome of this proceeding, and then terminated Docket No. ER84-283-000.

2. Staff Position

Staff recommends that MSS be allowed a 15.35% rate of return on common equity (Staff Ex. 34). This 15.35% is composed of an estimated growth rate MSU's dividend of 3.96%, of a current adjusted dividend yield of 11.32% and of a flotation adjustment of 0.07% (*id.*). Staff relies primarily on a DCF analysis to arrive at that figure but it also uses several other approaches to verify the results of its DCF analysis. One method is an equity valuation model resulting in a cost of equity in the 13.0%-15.3% range, at a 95% confidence level (Staff Ex. 7, pp. 18-22). In another approach, Staff compares the results of its DCF analysis for MSU with an average DCF cost of equity of 14.66% for the electric utility industry (*id.* at 9-14). Finally, Staff confirms its DCF results by developing a fundamental risk analysis comparing MSU to 100 utilities used as an industry aggregate (*id.* at 24-29). Staff concludes that MSU's investment risk is higher than average and, therefore, that MSU's cost of common equity as shown by its DCF analysis should be higher than average (*id.* at 30).

As calculated, Staff's DCF analysis determines the return on equity required to invest in MSU, rather than in the operating companies, since the operating companies sell no common stock, are wholly owned by MSU, and therefore their market cost of common equity cannot be directly measured (*id.* at 2, 3). Staff uses a forward looking growth factor and a dividend yield adjusted to reflect the

compounding effect from the quarterly payment of dividends. Flotation costs of selling new common stock of .07% were added to the growth factor of 3.96% and the dividend yield of 11.32%, to determine the recommended cost of equity of 15.35%. (*Id.* at 6, 14-17; Staff Ex. 34.)

In particular, Staff considers the growth in retained earnings (br) and the growth from the sale of common stock at prices above or below book value (sv), as a basis for growth in dividends and earnings in determining the growth factor. The formulary means for determining this growth is expressed as growth in book value per share (g) equals internal growth (br) plus external growth (sv). Growth in book value per share is logical inasmuch as dividend growth in a regulated industry is based upon growth in earnings, which is based on growth in book value. (Staff Ex. 7, pp. 6-8.)

The internal growth component (br) is the product of the earnings retention rate (one less the dividend payout ratio) (b), times the rate of return on common equity (r). The dividend payout ratio for MSU has averaged about 70% between 1974 and 1981 and, with *Value Line's* projection of a 70% dividend payout ratio for 1985-87, Staff estimates a 70% prospective payout ratio and a 30% earnings retention rate. Staff then reviewed MSU's earned return on common equity for the period 1968-1981, compared that to the allowed rates of return on common equity for the operating companies in their State jurisdictions, took into account the return allowance recently approved for MSE by FERC, and considered *Value Line's* 1985-87 projected rate of return on average common equity, to arrive at its 14.7% estimate of MSU's earned rate of return (r). Staff's expected internal growth rate of 4.41% for MSU is the product of the 30% earnings retention rate times the rate of return of 14.7%. (*Id.* at 6, 14-15.)

The external growth component is the result obtained by multiplying the growth in total common equity from stocks sales (s) times the percentage of new common stock

which accrues to the current shareholders. Staff used a forward-looking analysis of MSU's common stock sales requirements for the period 1982-86 to determine MSU's growth from the sale of new common stock. Then Staff applied MSU's price/book ratio for the 12 months ending September 1983, to arrive at an external growth component of – 0.44%. Combining the 4.41% internal growth component with the – 0.44% external growth component yields Staff's recommended growth factor of 3.96%. (*Id.* at 15-17; Staff Ex. 34.)

For the other ingredient in the DCF formula, the dividend yield, Staff calculated a dividend yield of 11.05% for the 12 months ending September 1983 and then adjusted that figure to 11.32% to reflect quarterly compounding of the dividend, since Staff desired a yield that is based on dividends that are paid quarterly. Adding the adjusted dividend yield of 11.32% with the growth factor of 3.96%, Staff arrives at the DCF cost of common equity of 15.28%. Adjusting that figure by .07% for estimated flotation expenses to be experienced in future public common stock offerings, results in the Staff's recommendation of a 15.35% equity return allowance for MSS. (Staff Ex. 34.)

As indicated above, Staff performed several other analyses as a check on the results of its DCF study. The equity valuation model determined the necessary return on equity for the selected group of average electric utilities to sell at a market to book ratio of one. The specific group of utilities was selected on the basis of several fundamental risk criteria, such as: *Value Line* Safety Rankings; projected construction budgets and internal funds generation; earnings quality rankings; and percentages of electric revenues to total revenues. The companies also possessed average costs of common equity and average common equity growth rates. This study results in the prediction of an interval for cost of equity of 13.0%-15.3% at the 95% confidence level. (Staff Ex. 7, pp. 18-22.) Staff also estimated the average DCF cost of equity for the electric

utility industry by using the same method it used to estimate the cost of equity for MSU. This approach yielded an estimated cost of equity of 14.66%. (*Id.* at 13.)

The final check on the DCF analysis result is derived from developing a set of measures and determinants of risk with which to compare MSU to 100 utilities used as an industry aggregate. The measures and determinants included, but were not limited to, the following factors: common equity ratio, interest coverage, ratio of AFUDC to net income, and earned return on total capital. Staff concludes that MSU's common stock has been considered much riskier than average in recent years, which indicates that MSU's cost of equity should be higher than the industry average. (*Id.* at 24-29.)

3. LPSC Position

LPSC presented as its primary position testimony urging the use of the weighted average cost of equity allowed the operating companies in the various jurisdictions they serve. LPSC argues that this method could easily be implemented, would minimize differences in rates attributable to the rate of return allowances in retail and wholesale proceedings, and would not affect the ability of MSU to attract capital since payments and receipts of the operating companies cancel each other out. (LPSC Ex. 1, pp. 37-38; LPSC Ex. 4, pp. 52-56.) Recognizing that FERC has previously rejected this method in *Middle South Services, Inc.,* 16 FERC ¶61,101, at pp. 61,220-21 (1981), LPSC advocates reconsideration of the methodology. However, if a traditional approach should be used, LPSC recommends a cost of equity allowance of 15% (LPSC Ex. 4, p. 41). In this regard, LPSC relies on a basic DCF analysis to determine a rate of return for MSU and a rate of return for eight comparable companies. The dividend yield used for both MSU and the comparable companies is based on the February 1983 average high-low market price. (*Id.* at 10, 27.) LPSC analyzes historical growth rates

from 1970-1981 and then considers current growth rates, to project a growth estimate of 4.00% for MSU and 4.91% for the 8 comparable companies (*id.* at 17-23).

4. CNO Position

CNO's presentation on rate of return used the dividend-yield method, the earnings-price ratio method and historical rates of return, to demonstrate that MSS is entitled to a return on common equity of no more than 15.46% (CNO Ex. 1, pp. 10-23). The first two approaches are DCF methods designed to meet the Commission's requirements that forward looking analyses of rate of return be employed, *Middle South Services, Inc., supra,* at p. 61,222. The results of these methods were checked by using the comparable earnings test method, where MSU's required rate of return was compared to the range of reasonableness determined by returns of companies with comparable risks (CNO Ex. 1, p. 17). CNO concludes that the range of cost of equity for MSU should be 15.26% to 15.46%. And, since MSU's current financial difficulties reflect higher than average risk, CNO suggests that MSU earn a return of 15.46%, at the high end of the range. (*Id.* at 23.) At the hearing, CNO indicated that the 15.46% may be a half percentage point high, if events occurring between the submission of its testimony and the date of hearing continue in a similar manner (Tr. 3376). However, CNO is still advocating a 15.46% return allowance (CNO Initial Br., p. 58).

5. Arkansas Attorney General Position

The Arkansas Attorney General (A.A.G.) recommends a 14% return on equity based on two different DCF analyses. First, a traditional methodology to develop current dividend yield plus the expected dividend growth rate was used. A.A.G. stresses the importance of using a sustainable growth rate in the traditional formula. By examining the historical pattern of earned return and payout ratios for MSU and determining if such trends will continue, A.A.G.

estimates a future growth rate. The sustainable growth potential of approximately 2.8% is determined by taking MSU's average for return on equity for the past 5 years of 12.96%, subtracting therefrom the recent dividend to book ratio of 9.4%, and finally subtracting .78% for dilution from selling new stock at prices below book value. A.A.G. relies on a dividend yield of 11% for MSU from the four months of November through February and arrives at a total return on equity of 13.8%. (Ark. Ex. 1, pp. 16-23.)

A second approach, involving an econometric model was followed to test the traditional DCF model. The econometric approach used the following formula: r = k + [D/B - D/P], where r equals expected book return, k equals required return, D equals dividends, B equals book value per share and P equals market price per share. This approach indicates a need for a 13.819% return on equity and corroborates the result of 13.8% determined using the traditional DCF approach. (*Id.* at 24-33.)

In addition, A.A.G. used another method to arrive at a 14% return on common equity—the presumption of validity method (POVM). This method compared conditions prevailing when MSS' latest approved return was determined, to current market conditions. It was concluded that conditions are similar and that no increase in the previously allowed return on equity of 14% is necessary. (*Id.* at 3, 14-16.)

6. Discussion and Resolution of Return on Equity

The primary position of the LPSC urging the use of the weighted average cost of equity allowed the operating companies in the various jurisdictions they serve, will not be adopted. In *Middle South Services, Inc., supra* at p. 61,221, the Commission rejected this some methodology when proposed therein by LPSC, stating that:

> "We agree with the judge that averaging various returns on equity established at different times in dif-

> ferent jurisdictions which use different policies, standards and methodologies in setting rates is not the proper way for this Commission to establish a just and reasonable wholesale rate."

The Court of Appeals affirmed the findings of the Commission and approved the equity allowance granted by the Commission in *Louisiana Public Service Commission v. F.E.R.C.*, 688 F.2d 357, 362 (5th Cir. 1982).

As noted above, LPSC also presented a DCF analysis as an alternate approach should its primary position be rejected. The recommendation under this traditional approach is 15% and is close to the 15.35% recommendation of the Staff. (LPSC Initial Br., p. 82.) However, LPSC has utilized a one month dividend yield employing the average high-low market price for February 1983 of 10.88%. This runs counter to the Commission preference for using representative dividends and stock prices to calculate yield. For example, in *New England Power Company,* 22 FERC ¶61,123, at p. 61,187 (1983), the Commission used an eight month period to calculate the representative dividend yield. Here, where the dividend yield for the 12 months ended February 1983 has ranged from 10.62% to 13.55%, a spot dividend yield is not representative. Substituting the dividend yield determined by Staff pursuant to a 12 month average, into LPSC's formula yields a return on equity allowance increase of .44% (11.32% minus 10.88%) or a recommended return on equity allowance of 15.44%.

The two different DCF based analyses and the presumption of validity method (POVM) relied upon by A.A.G. are defective and do not produce just and reasonable rates. The first DCF approach is flawed because A.A.G. did not use a representative dividend yield nor did it use a forward-looking growth rate. The dividend yield determined by A.A.G. is based on a four month period ending in February 1983, during which there were large fluctuations in the yield. Therefore, it is not a representative period

for determining dividend yield, as required by *New England Power Co., id.*

Also, in calculating the growth rate, A.A.G. analyzed the historical earned returns for 1978-1982 and then projected an average earned return of equity of 13% because it is within the range experienced historically (Ark. Ex. 1, pp. 21-22; Ark. Ex. 2). A.A.G. relies too heavily on historical returns without attempting to derive a forward-looking expected earned rate or return on common equity. As a result, A.A.G. is not following the Commission's preference for a forward-looking DCF analyses. See *Central Illinois Light Company,* 10 FERC ¶61,248, at pp. 61,480, 61,482, n. 40 (1980). For the future rate of growth in new shares, A.A.G. advocates a 6% rate which is below the average of 11.13% experienced historically (Ark. Ex. 1, p. 22). However, it was not shown that the 6% estimate is the result of a forward-looking analysis.

Therefore, the defective overall growth rate and the miscalculation of the dividend yield require rejection of A.A.G.'s proposed return. In addition, A.A.G. failed to adjust its rate upward for common stock flotation costs and it neglected to reflect quarterly compounding of dividends. Recovery of flotation costs is allowed to the extent these costs are incurred on new equity, *New England Power Company, supra,* at p. 61,189. Also, quarterly compounding of dividends is necessary since dividends are not paid out annually nor continuously, but quarterly, *Minnesota Power and Light Company,* 3 FERC ¶61,045, at p. 61,143 n.9 (1978).

Moreover, A.A.G.'s econometric model is also defective, A.A.G. used a single day's spot cost of common equity and the expected earned rate of return was derived from normalizing historical 1982 results, rather than by using forward-looking data (Ark. Ex. 1, pp. 30-31). This approach, therefore, is not consistent with the above discussed Com-

mission preferences for using a representative time period to determine dividend yields and a forward-looking analysis to ascertain the growth factor. In addition, A.A.G.'s assumption that all electric utilities are equal in risk (except for General Public Utilities) was not established on the record.

Further, the POVM presented by A.A.G. suggests that no increase in the allowed rate of return of 14% from MSS' prior case is justified because prevailing market conditions are comparable to conditions as they were when the 14% was allowed. As Staff correctly points out, the return found to be just and reasonable in Docket No. ER79-277, was Staff's estimate of 15.25%, but the rate was limited to MSS' tariff as filed, which requested a rate of 14%, *Middle South Services, Inc., supra,* at pp. 61,219-61,222; Tr. 6571, 6572 and 6580). Accordingly, it is reasonable to conclude that the POVM results in a 15.25% allowance for return on equity, rather than a 14% allowance.

Overall, the position advanced by the A.A.G. is not in line with Commission precedent and will not be followed.

CNO relied on three methods to support its recommended allowance of 15.46%. The dividend yield method employed a spot yield (April 12, 1983), adjusted that yield to a market-to-book ratio equalling one, and then added in a growth factor. Although CNO believes the current yield represents current investor evaluation, such a dividend yield does not comport with the Commission requirements, since a representative period for dividend yield should be more than one day. *See New England Power Co., supra* at p. 61,187. CNO's addition to the adjusted spot dividend yield was a low growth factor of 2.7% CNO does not consider that the historical six year average growth rate of 3.92% can be maintained, so it adjusted the growth factor down to 2.70%, which is the latest historical three year average growth rate (CNO Ex. 1, p. 20; CNO Ex. 2, p. 6). Although this method yielded a return

allowance of 15.26%, modifications to the dividend yield to reflect a more representative period (such as the 12 month period used by Staff and MSS) and utilization of a growth factor which is forward-looking (such as Staff's 3.96%), would result in a recommended return in excess of 16%. The above noted problems require rejection of CNO's dividend yield methodology.

CNO's second approach involved an earning price analysis, which yields a 15.45% return allowance. It can be significantly modified by simply substituting a three year divided payout ratio for the six year payout ratio used by CNO (CNO Ex. 2, pp. 2-6). The 1977 and 1978 data used lowers the return allowance to the 15.46% cost of common equity recommendation (*Id.* at 2). With the use of a spot earnings/price ratio of April 12, 1983 and the significant variance in the return allowance depending on which historical average dividend payout ratios are used, this method is found to be unreliable for determining the appropriate return on common equity.

While CNO did consider the 13.31% historical return on average common equity for MSU for 1982, CNO's recommended range of 15.26%-15.46% for return on common equity is made up of its dividend-yield approach result and the earnings-price ratio result, both methods of which have been determined to be unreliable.

The methods advocated by MSS also have certain deficiencies. MSS has failed to consider fully the costs of MSU's embedded common equity. The emphasis on new common equity acquired through retained earnings and on new common equity based on annual common stock sales, excludes the embedded common equity. By so doing, MSS is obtaining a recommended rate of return for only a portion of MSU's common equity. Appropriate consideration of MSU's entire common equity, for example by applying the lower return on new common equity represented by retained earnings of 15.6% (MSS Ex. 16, Sch. 7-A), to the

embedded common equity, would lower the return allowance advocated by MSS.

MSS' approach to determine one rate for new retained earnings and another rate for new common stock issues is also subject to criticism. The difference in costs of these equity components does not appear to be as significant as MSS suggests. While Staff recognizes a 0.07% flotation cost for the issuance of new common equity, MSS suggests that approximately 1% additional cost for this new equity is necessary to allow for market pressures. Staff's approach to allow for the flotation cost addition is more reasonable. Further, MSS' reliance on an earnings price ratio method to determine the proper cost of new common stock, is not in line with *Public Service Company of Indiana, Inc.*, 7 FERC ¶61,319, at p. 61,709 (1979).

Despite the flaws mentioned and the use of a different dividend growth rate for pre-1984 and post-1983 years while using a constant growth DCF model, MSS' cost of retained earnings recommendation is close to Staff's common equity recommendation. In fact, MSS states that, assuming *arguendo* that it would use the cost of retained earnings as MSU's overall cost of its equity, MSS would have shown a cost of equity of 16.2% in its direct testimony and 16.0% at the time of its rebuttal testimony (MSS Initial Br., pp. 30-31). Of course, MSS reduced its overall common equity recommendation to 16% during the hearing because of the changed market conditions then present.

Staff relied on a forward-looking market-oriented DCF analysis. As mentioned previously, such an approach is preferred by the Commission, *Central Illinois Light Co.*, 10 FERC ¶61,248,at p. 61,489 (1980). Staff's use of estimated dividend growth through growth in book value per share is also consistent with *New England Power Company, supra.* The rate of growth from internal reinvestment of retained earnings involved an analysis of the historical record, as well as forward-looking sources such

as *Value Line* projections. The external growth factor percentage included an analysis that considered the past as well as projections of stock sales requirements for the future. Therefore, the Staff's estimates of MSU's future growth rates are well supported.

Also, Staff, as did MSS, used a dividend yield for a study period of 12 months. Such an approach comports with the aforementioned Commission preference that a representative period be used. Staff adjusted its dividend yield to reflect quarterly compounding of the dividends, which is in line with *Minnesota Power and Light Co.,* 11 FERC ¶61,312 (1980). Additionally, Staff determined a flotation cost allowance of 0.07% to compensate MSU for the expected future costs of issuing new common equity, as is allowed by *New England Power Company, supra* at p. 61,189.

Further, it should be noted that Staff's DCF methodology was approved by the Commission in the prior MSS proceeding, *Middle South Services, Inc., supra* at p. 61,222 (1981).

Staff's overall rate of return on equity recommendation initially was 15.86% (Staff Ex. 7, p. 30). However, based on updated information concerning MSU's dividend yield, book value and average price for the 12 month period October 1982 through September 1983, Staff lowered its recommendation to 15.35% to account for these market changes (Staff Ex. 34; Tr. 3417-18).

Staff also requests that reliance be placed on the existing record in the proceeding without reference to later available MSU common stock prices and recent articles purporting to show that the nuclear power industry is in difficulty (Staff Initial Br., pp. 29-30). MSS counters that these sources should be considered (MSS Initial Br., p. 34). MSS asserts that the price of common stock from October 1983 to March 1984 approximates the range of prices examined by Staff and MSS in their initial rounds of tes-

timony, wherein Staff recommended a 15.86% return on equity allowance (*Id.* at 34-35).

On the updating issue, the Commission has consistently held that it may consider post-hearing changes in capital market conditions, *Pennsylvania Power Company,* 26 FERC ¶61,354, at p. 61,778 (1984); *Union Electric Company, et al.,* 26 FERC ¶61,125 at p. 61,314, n. 3 (1984); *Pacific Gas and Electric Company,* 20 FERC ¶61,190, at p. 61,373 (1982); *Arkansas Louisiana Gas Co.,* 19 FERC ¶61,012, at pp. 61,014-15 (1982); and *Arizona Public Service Company,* 18 FERC ¶61,197, at p. 61,400 (1982). In light of these cases, it is appropriate that updated conditions be considered in deciding the rate of return allowance.

Staff, MSS and other parties felt obligated to either modify or consider modifying their recommendation based on market conditions that existed at the time of hearing. Staff and MSS both reduced their recommendations, principally because of the increase in the price of MSU stock. While MSS relied on a market price for MSU common stock of $13.50 in its direct case, recognition was given in its rebuttal testimony to the fact that the midpoint market price for MSU for the twelve months to that date had risen to $14.375 (MSS Ex. 15, p. 1). Staff adjusted its return recommendation because the average market price of MSU stock used in its direct testimony increased from approximately $14 to $15.396 at the time of hearing (Staff Ex. 7, Sch. No. 3; Staff Ex. 34). A review of the average price of MSU common stock for the period October 1983 through December 1984 demonstrates that he resultant average price of the stock over this post-hearing time period is $13.20 (Standard and Poor's Corporation Stock Guide, October 1983—December 1984). Therefore, the recent fifteen month data showing the MSU average stock price to be $13.20 is more comparable with the MSU average stock price of approximately $13.50 relied on by MSS and Staff in their initially filed testimony. Further,

greater reliance should be placed on the most recent data than on the data used at the hearing to update MSS' and Staff's positions.

Moreover, the perception of risk for electric utilities with nuclear plant construction is higher today than it was prior to and during the hearing. Numerous articles have been written subsequent to the hearing regarding electric utilities and nuclear plant construction. While not specifically relying on these articles to determine a specific percentage amount to include in the return allowance determined here, it is clear that the perception of risk to the investor has increased. The *Time* magazine edition of February 13, 1984, p. 34-42 describes various setbacks to the nuclear industry, such as the bond default by the Washington Public Power Supply System, the denial by the Nuclear Regulatory Commission of an operating license for Commonwealth Edison's new Byron plant and the cancellation of Public Service Company of Indiana's Marble Hill plant. In the May 13, 1984 edition of *The Washington Post,* an article at p. A1, addresses the following subjects: the likely financial collapse of the nuclear power plant project in Seabrook, New Hampshire and a resultant potential bankruptcy filing by Public Service Company of New Hampshire; the inabilities of Long Island Lighting Company's Shoreham nuclear plant to receive approval to operate; the abandonment of Public Service Company of Indiana's Marble Hill project; and the inability of Consumers Power of Michigan to finance the work and pursue corrective action on its Midland nuclear plant. The article emphasizes that each of these utilities could be forced in bankruptcy because of skyrocketing costs for nuclear projects and that such an occurrence could drive up the costs of borrowing for all utilities with nuclear plants. In the June 27, 1984 edition of the *New York Times,* an article at Section D, p. 1, discusses the recent and real potential for bankruptcy filings for several utilities with giant nuclear projects and the adverse effects a filing could have

on ratepayers and investors nationwide. The *Time* magazine edition of July 23, 1984, beginning at p. 81, contains an article focusing on the current problems of several electric utilities with ambitious nuclear power programs and the negative effects to ratepayers and investors for the entire industry if any major electric utility declares bankruptcy. Other issues of *Time* magazine, *The Wall Street Journal*, *The New York Times* and other publications have also addressed the status of electric utilities and nuclear plant construction results (See MSS Initial Br., pp. 36-39). In a forward-looking, market-oriented DCF approach, these occurrences and perceptions must be considered in determining the proper return allowance for MSU.

In summary, the LPSC argument for use of a weighted average cost of equity has been rejected. Moreover, the secondary LPSC analysis, the A.A.G. analyses and the CNO analyses were found unreliable because the manner in which the methods were utilized, as discussed earlier, does not comply with Commission precedent. And, while MSS's position is not fatally flawed, it suffers from the defects previously discussed. Staff's method is the best reasoned and supported return on equity evaluation, but it must be reassessed in light of significant post-hearing event.

Based on a review of the record and the above discussion, it is determined that the appropriate zone of reasonableness of the return on equity to apply to the Service Schedules in the 1982 System Agreement, should range from 15% to 16%. While it can be argued that Staff's analyses could support a lower return on equity than 15%, this will nonetheless be adopted as the lower end of what is just and reasonable because of current market conditions and the perceived risks resulting from the system's large nuclear investment. Since no party advocates a higher return than 16%, since MSS has reduced its request from 18% to 16%, and because of the aforementioned current market conditions and perceived risks relating to nuclear

investment, the high end of the zone of reasonableness is being set at 16%. Further, when the risk element and recent developments relating to nuclear power are taken into account, it must be concluded that the return on equity should be set toward the high end of the zone of reasonableness. As a result, a 15.75% return on equity is considered just and reasonable and is hereby adopted.

B. Capital Structure

CNO argues that significant errors exit in MSS' estimates of capital ratios and costs for the 1982 year-end, based on a comparison of the operating companies' actual 1982 year-end figures as shown in their annual reports, with MSS Ex. 6, Exhibit IX, Sheet 1 of 4 (CNO Ex. 1, pp. 27-28). CNO offered CNO Ex. 2, p. 15, which utilizes the operating companies' 1982 year-end reports, and avers that substituting the exhibit for MSS Ex. 6, Exhibit IX, Sheet 1 of 4, would make the adjustment it advocates. CNO relies on *Middle South Services, Inc., supra* at p. 61,223, as supporting the use of the latest available evidence of a company's capital structure when determining the appropriate capital structure. (CNO Initial Br., pp. 65-67.)

MSS responds that CNO's argument is without foundation. MSS also relies on *Middle South Services, Inc., supra,* and argues that the Service Schedules (MSS-1, MSS-2 and MSS-4) always use actual recorded data and not estimates or fixed target ratios. MSS states that the data contained in MSS Ex. 6, Exhibit IX, Sheet 1 of 4, of MSS' filing was intended only for illustration and was not actually employed in the billing calculations. (MSS Reply Br., p.5.) MSS explains that changes to reflect the actual capital ratios and costs (other than return on equity) by utilizing the selling company's individual capital structure at December 31 of the previous year, are made as of June 1 each year (MSS Ex. 1, p. 10). MSS, therefore, asserts that ordering it to revise Exhibit IX, Sheet 1 of 4, would

be a meaningless exercise and that CNO's argument should be rejected (MSS Reply Br., p. 5).

The Commission in *Middle South Services, Inc., supra* at p. 61,219, accepted MSS' proposed formula as the rate and also ordered that, "... as the actual capitalization ratios change, they should be reflected in the cost of service formula approved herein", (*Id.* at p. 61,223). Since MSS is employing the capitalization ratios in its billings in the formulary manner consistent with the ruling in this prior MSS Opinion, CNO's proposal to require MSS to revise MSS Ex. 6, Exhibit IX, Sheet 1 of 4, is denied.

CNO also objects to the MSS proposal to time date the cost of capital in MSS-4 for embedded debt and capitalization ratios related to the White Bluff Coal Units, to the period of construction and to use a current cost of common equity. CNO explained that time dating is not a widely accepted practice and that such an approach may result in under collection or overcollection of revenues from the various customer classes. This approach, according to CNO, should be abandoned as unjust and unreasonable and unduly discriminatory. (CNO Ex. 1, pp. 28-29.)

MSS counters that the monthly billing charge in Service Schedule MSS-4 reflects the selling company's individual capital structure and costs of debt and preferred stock associated with the designated generating unit from which the sale is made, and that such charge, although not precise, is reasonable. MSS also points out that CNO does not quantify how much of an undercollection or overcollection, if any, is occurring as a result of the billing procedures MSS employs. MSS further states that the practice of time dating is consistent with the purpose of Service Schedule MSS-4 to base charges on the costs of a contractually designated generating unit. Additionally, MSS avers that the MSS-4 procedure represents a carry-over of the procedures used in MSS-1 of the 1973 System Agreement for participation units, and that the Commis-

sion granted implicit approval of that procedure in *Middle South Services, Inc., supra.* (MSS Initial Br., pp. 42-43.)

Finally, LPSC objects to the procedure of calculating monthly billing charges under MSS-1 MSS-2 and MSS-4 reflecting the selling company's individual capital structure and its average embedded costs of debt and preferred stock. Instead, it proposes to use consolidated MSU capital structure ratios and costs of debt and preferred stock, exclusive of MSE, for inclusion in the pricing formulae to the 1982 System Agreement. (LPSC Ex. 1, pp. 33-36.) MSS points out that the 1982 System Agreement, which includes the pricing formula of MSS-1, reflects the costs of specified generating units as does the pricing formula of MSS-4 (MSS Ex. 1, p. 10). MSS asserts that the goals of the formulae are to track costs of each company's own units, and the use of each company's own capital structure and embedded costs of debt and preferred stock is consistent therewith. (MSS Initial Br., pp. 40-41.)

The proposals of CNO and LPSC regarding capitalization ratios and embedded costs of debt and preferred stock are rejected. MSS's arguments are better taken and more persuasive. In addition, the procedures challenged by CNO and LPSC are consistent with the Commission's rulings in the prior MSS proceeding, *Middle South Services, Inc., supra.*

V. Miscellaneous Issues

A. Periodic Review Conditions

Service Schedules MSS-1, MSS-2, and MSS-4 of the 1982 System Agreement contain formula rates which allow the automatic allocation of certain capital related costs, operation and maintenance costs and administrative and general costs, after they have been incurred and recorded in compliance with the Uniform System of Accounts (MSS Ex. 1, pp. 11-12). Service Schedule MSS-3 is similar to a fuel adjustment clause because the provisions permit the

automatic allocation of current fuel and related costs. The provisions of these service schedules may be construed as a "cost of service" form of rate design. (MSS Ex. 1, p. 12-13.)

In light of this, LPSC contends that the "cost of service" tariff represented by Service Schedules MSS-1, MSS-2, MSS-3 and MSS-4 should only be approved if MSS is required to present for periodic review by FERC, the costs that have formed the basis of the rates charged. LPSC would have this review occur at least every three years. Also, in such a review, LPSC would require that MSS prove the reasonableness of all the costs. (LPSC Ex. 1, p. 37.)

LPSC asserts that, without periodic review, a cost of service rate design design may permit the recovery of expenditures that were imprudently incurred, or were abnormal and should be amortized over a period of time (Tr. 4097). LPSC also suggests that the situation could result in retroactive ratemaking (id.). Although LPSC recognizes that the costs allocated under the 1982 System Agreement are recorded pursuant to the Uniform System of Accounts and are subject to audit by independent, outside auditors and the Commission's own audit staff as part of regular field audits, it denies the effectiveness of this safeguard. LPSC contends that the purpose of an audit is to determine whether the company spent the money and recorded it properly, while the function of a periodic review is to determine whether the cost should be recovered in the tariff consistent with sound ratemaking.

MSS opposes any periodic review conditions, regardless of what form of cost of service rate design is adopted herein (MSS Initial Br., p. 13). MSS argues persuasively that LPSC has not taken into account the safeguard inherent in Section 206 of the Federal Power Act (FPA), 16 U.S.C. §824e, which permits initiation of a hearing should an interested party or the Commission have reason

to suspect that improper costs are being allocated. Thus, any customer who believes that costs were imprudently incurred or improper, may file a complaint with the Commission. Further, MSS points out that the costs allocated under the 1982 System Agreement will be subject to review during ongoing retail and wholesale rate proceedings and that any questionable costs discovered in those proceedings could become the basis for a Section 206 review of the 1982 System Agreement.

More importantly, however, MSS correctly asserts that the Commission has previously rejected LPSC's argument. In the 1981 MSS decision, the commission rejected requirements under which MSS would have had to file, for for review and possible refund, annual report showing the development of charges under the cost of service formula rates of the 1973 System Agreement, and capitalization data concerning the service provided and other charges included in the formula rates during the previous year, *Middle South Services, Inc.*, 16 FERC ¶61,101, at p. 61,219 (1981). The Commission considered the filing requirements unnecessary because the costs involved are subject to audit by the Commission and can also be investigated under Section 206 of the FPA, *id.* This holding and the Commission's rationale was specifically affirmed by the U.S. Court of Appeals for the Fifth Circuit in *Louisiana Public Service Commission v. F.ER.C.*, 688 F.2d 357, 361 (1982), *cert. denied* 460 U.S. 1082 (1983).

Moreover, in a recent decision, the Presiding Judge found that no reporting or refund conditions should be placed on MSE as to costs within the cost of service formula of the Unit Power Sales Agreement, *Middle South Services, Inc.*, 26 FERC ¶63,044, at p. 65,124 (1984). There, the reasoning was that independent, outside audits and FERC's audits make such conditions unnecessary, *id.*

In light of the above, LPSC's request for periodic review conditions must be denied. The Commission has set out

that its periodic audits will preclude recovery of improperly incurred costs, and that an additional safeguard exists in Section 206 of the FPA, which permits the institution of a hearing should an interested party or the Commission have reason to suspect that improper costs are being allocated. Therefore, periodic review conditions are unwarranted.

B. Reclassification of Transmission Investment

The 1982 Agreement provides in Section 3.06 of Article III, for joint planning and construction of high voltage transmission facilities needed to improve reliability and facilitate power pooling transactions. Further, Section 3.01 of Article III sets out that costs associated with the construction, ownership and operation of the facilities which are used for the mutual benefit of all the companies will be equalized among the MSU operating companies. The basis for equalizing the cost of the transmission facilities installed for the companies' mutual benefit is set forth in Service Schedule MSS-2.

Under Service Schedule MSS-2, the following facilities are designated as Inter-Transmission Investment and are subject to cost equalization:

(a) Transmission lines operated at 230 kV or higher voltages, to the extent that the investment costs of such lines are not supported in billings to non-associated utilities under other agreements.

(b) Transmission substations with three or more lines operated at a voltage of 230 kV or higher, to the extent that the investment costs of such substations are not supported in billings to non-associated utilities under other agreements.

(c) All other transmission lines operated at 115 kV and higher from the owning company's last substation to the connecting point of another company (either another MSU operating company or a non-associated utility), to the ex-

tent that the investment costs are not included in billings under other agreements.

The costs of these facilities are to be equalized among the MSU operating companies on the basis of their Responsibility Ratios. These costs include annual ownership costs, and operation, maintenance, administrative, and general expenses related to the designated transmission lines. Companies with more than their share of Inter-Transmission Investment receive payments from companies with less than their share of Inter-Transmission Investment. The transmission facilities MSS proposes for inclusion in Inter-Transmission Investment are listed in Exhibit XXX of MSS Ex. 19.

CNO asserts that MSS has failed to justify the inclusion of many of the transmission facilities in the cost equalization formula. CNO calculates that approximately one-third of the facilities listed in MSS Ex. 19, Exhibit XX, should be excluded because they are not part of the integrated inter-transmission system used for power supply to serve the four operating companies. CNO's recalculation of the transmission lines it would equalize among the MSU operating companies and the cost adjustments resulting therefrom are shown on CNO Ex. 75. (CNO Initial Br., pp. 74, 75.)

In particular, CNO contends that MSS arbitrarily equalizes all lines 230 kV and above, and ignores whether those lines actually serve the function of inter-company energy exchange or inter-system reliability. CNO suggests that the function of a line, rather than its voltage, should be the basis for inclusion or exclusion of the line from the Inter-Transmission Investment. (CNO Ex. 3, pp. 39-40.) CNO also argues that it cannot be reasonably determined whether ratepayers in one company's service area actually benefit from the 115 kV lines that connect two other companies (CNO Ex. 3, pp. 40-41; CNO Ex. 5). In addition, CNO avers that the cost burden of such a 115 kV line is

not divided equally because each company will get a different amount of equalization credit for the same line, depending on the length of the line in each state (CNO Ex. 3, p. 41). Further, CNO avers that Middle South's proposed intertransmission network is not an integrated system. An integrated system is defined as one where all generating plants are connected into a grid capable of functioning with the loss of one or more generating facilities, and as a system where the grid is connected to foreign utilities for economy and reliability purposes. (CNO Ex. 3, p. 42.)

CNO suggests that transmission lines perform three functions: (1) to connect generating plants to form an integrated system; (2) to connect the integrated system to foreign utilities for economy and reliability; and (3) to connect the integrated system to load centers. CNO would classify transmission lines performing functions (1) and (2) as power supply transmission qualifying under Service Schedule MSS-2 as Inter-Transmission Investment, but would classify transmission lines performing function (3) as general transmission and exclude them from equalization under Service Schedule MSS-2. (CNO Ex. 3, p. 43.) Moreover, CNO would equalize only transmission lines comprising an integrated transmission network used for power supply at the interstate level and would exclude lines used for power supply within a state (CNO Ex. 3, p. 48; CNO Ex. 75). Accordingly, all 115 kV transmission plants would be excluded because they are at the State level (CNO Ex. 3, p. 46).

Further, CNO argues that MSS's proposed transmission equalization unduely discriminates against NOPSI. NOPSI's service area approximately corresponds to New Orleans' city limits, making NOPSI's transmission facilities qualifying for equalization necessarily smaller in number and size than those of the other operating companies. As a result, NOPSI is, and will remain, a short company required to make substantial equalization payments. Since

CNO contends that much of these payments are to equalize facilities that provide NOPSI no direct or indirect benefit by serving the integrated, intersystem pool network, an undue discrimination situation results from the MSS transmission equalization procedure. (CNO Initial Br., p. 77.)

CNO recommends, therefore, that its classification of facilities qualifying for equalization under Service Schedule MSS-2, as shown on its CNO Ex. 75, be adopted.

On analysis, it appears that the MSS position on transmission equalization is better taken. First, CNO's proposed exclusion of all 115 kV low voltage lines is unwarranted. The Commission has included low voltage lines as part of transmission investment installed for the benefit of all customers where the lines served a power supply function. *See, Public Service Co. of New Hampshire,* 22 FERC ¶63,083 (1983), *aff'd,* 24 FERC ¶61,007 (1983); *Public Service Co. of Oklahoma,* 57 FPC 1041 (1977); and *Sierra Pacific Power Company,* 53 FPC 1795 (1975). In these cases, no distinction was drawn between low voltage lines operating at the state level and those functioning at the interstate level. Moreover, in *Florida Power & Light Co.,* 21 FERC ¶61,070, at pp. 61,242-43 (1982), the Commission reasoned that it would be inappropriate to distinguish between transmission lines on the basis of voltage level if the lower voltage lines perform the same power supply function as the higher voltage lines.

In this latter regard, if all 15 kV transmission lines were eliminated from the Inter-Transmission Investment, that would exclude certain lines forming interconnections between operating companies or with neighboring, non-associated utilities which are used to facilitate the exchange of energy (MSS Ex. 17, p. 76). For example, the two 115 kV lines connecting LP&L's Sterlington plant with AP&L's Crosset substation and the two 115 kV lines connecting MP&L's Natchez plant with LP&L's Red Dam and Plan-

tation substation would be affected (CNO Ex. 6; Tr. 2066-70.) Therefore, the total exclusion of all 115 kV lines from the Inter-Transmission Investment, as suggested by CNO, is not justified.

Moreover, CNO's argument that some of the lines, which are power supply related, serve only the customers of the MSU operating company which owns them (CNO Ex. 3, pp. 42, 44), has been addressed by the Commission. In *Otter Tail Power Company,* 12 FERC ¶61,169, at p. 61,421 (1980), the Commission held that, where generation and transmission facilities are electrically integrated and centrally controlled (as in the case with Middle South System), transmission lines benefit all customers, even if it cannot be shown that power in a particular line reaches certain customers. Also, the *Public Service Co. of New Hampshire, supra,* 22 FERC ¶63,083, at pp. 65,263-65,269, the Commission set out that, where transmission facilities of several utilities form an electrically integrated power pool, no transmission lines forming that pool should be treated as if they had no effect on the operation of all other lines forming the pool.

In support of the lack of benefit argument, CNO points to the 161 kV line between AP&L's Dell substation and the Madrid Plant (CNO Ex. 3, p. 44). CNO questions the ability of that line in Northeast Arkansas to serve customers in New Orleans on the basis that the transmission facilities included in the Inter-Transmission Investment by MSS do not, by themselves, form an integrated transmission system (CNO Ex. 3, p. 42). However, it was brought out that it is possible for energy which enters the system over the Dell to Madrid line to be transmitted to New Orleans, even if it is not over facilities forming the Inter-Transmission Investment (Tr. 2073-74). Under the circumstances, CNO's argument regarding exclusion of transmission lines on the basis that they benefit only one company is unpersuasive.

Similarly, the CNO argument regarding the disproportionate investment in 115 kV transmission lines used interconnect two of the MSU operating companies (CNO Ex. 3, pp. 40-41; CNO Ex. 5), is not well taken. Even though one operating company might have more investment in a 115 kV line since more of the line lies in its territory, this does not warrant exclusion of that line from equalization under Service Schedule MSS-2. Since the line connects the two MSU operation companies, it is performing a pooling function and rendering the operations of the interconnected companies more economical and reliable. The line, therefore, does meet the purpose of Inter-Transmission Investment and is appropriate for equalization.

Concerning the CNO argument that the 230 kV transmission lines which transport energy from the integrated or "backbone" transmission system to load centers be designated as general transmission and excluded from equalization, the only such line identified is the one from AP&L's Ritchie plant to Brinkley (CNO Ex. 3, pp. 43-45). However, the Brinkley line and the other 230 kV lines are not radial transmission lines. Rather, each of these lines connects with 115 kV transmission facilities to form a loop over which power may flow to achieve reliable service. For example, the two kV lines from Ritchie to Pine Bluff both transfer energy within Arkansas and transfer energy between States (Tr. 2072-73). Further, even if the 230 kV lines were considered radial lines, the Commission has indicated that a radial transmission line should be considered part of the overall power supply transmission facilities of a utility, unless the radial line is electrically isolated and operates under substantially different conditions from other lines on the system, *Public service of Indiana,* 56 FPC 3003 (*1976*), *aff'd sub nom. Public Service Company of Indiana v. F.E.R.C., 575* F.2d 1204 (7th Cir. 1978). In line with this rationale, the Commission in *Florida Power and Light Company, supra* at p. 61,242, refused to treat certain radial transmission lines differently from other trans-

mission lines forming the utility's integrated transmission network because it was unable to conclude that the radial lines were not used in delivering power to the complaining municipality.

In addition, the CNO recommendation that the study of predominant load flows on the system be used to determine which of the power supply transmission lines operating at 235 KV are to be included in Inter-Transmission Investment (CNO Ex. 3, p. 45), must be rejected. MSS correctly asserts that the flows on its transmission system vary widely from hour to hour in magnitude and direction depending upon such factors as relative loads in different parts of the system, economic dispatch and transmission and generation outages (MSS Ex. 17, p. 76). As a result, to adopt the predominant flow basis could exclude from Inter-Transmission Investment certain 230 kV or 345 kV lines which have an integral part in facilitating the exchange of energy among the operating companies, merely because their flow pattern at a particular point in time did not show the exchange function. Further, the Commission does not sanction the predominant flow method for establishing the function of a transmission line since, at a specific point in time, the dynamic development of an integrated transmission system will appear "frozen," as if particular segments are used to serve only one or several particular customers. The Commission has pointed out that this time specific perspective distorts reality. *Public Service Company of Indiana, supra* at 3036. Also, the Commission in *Missouri Utilities Company,* 10 FERC ¶61,297, at p. 61,599 (1980), elected not to treat certain transmission lines as exclusively used by certain customers, even when the lines had originally been intended for the exclusive benefit of those customers, since the lines had become part of an integrated transmission system and since power can and did flow both ways on the lines.

Finally, the CNO argument that the facilities proposed for equalization by MSS results in undue discrimination

since NOPSI's transmission facilities are smaller in number and size than those of other companies, which results in NOPSI paying substantial transmission equalization payments, is unpersuasive. NOPSI does get the benefit from the transmission facilities proposed by MSS for equalization since those transmission lines facilitate the exchange of energy between the MSU operating companies and enhance the reliability of the system. Further, while NOPSI may have less Inter-Transmission Investment than other operating companies, it correspondently has less cost responsibility for constructing Inter-Transmission Investment than the other companies. The payments NOPSI has to make, therefore, are not unduly discriminatory but are justified on the basis that NOPSI should be responsible for its proportionate share of the cost of transmission facilities which serve the mutual benefit of all the operating companies by facilitating energy exchange and reliability.

Overall, CNO has not established that any of the transmission lines proposed by MSS for equalization as Inter-Transmission Investment, do not perform an energy transfer function between the operating companies and enhance the reliability of the system. Therefore, the CNO criticisms of the MSS transmission equalization proposal must be rejected. Instead, given the well-reasoned arguments by MSS and the record herein relating to transmission equalization, it must be concluded that the proposed designation by MSS of transmission facilities as Inter-Transmission Investment subject to equalization under Service Schedule MSS-2, should be approved.

C. Reclassification of Generating Units

Service Schedule MSS-1 of the 1982 System Agreement provides that reserve capacity sales are to be priced according to the capital and operating costs (excluding fuel) of the selling company's intermediate generating units. Intermediate generating units are defined by MSS as oil or gas-fired plants.

CNO opposes the classification of intermediate generating units based upon fuel. CNO submits that the classification should be made on the basis of use. CNO would determine use by considering each units capacity factor and its average loading. Capacity factor, as defined by CNO, is calculated by multiplying the unit's capacity by the hours in a year, and then dividing that result into net generation of the facility. Average loading is ascertained by multiplying the number of hours in a year the unit is operated by the unit's capacity, and then dividing that figure into the net generation of the facility. CNO would classify a unit having a high capacity factor and high average loading as base load while a unit would be classified intermediate if it has a relatively high capacity factor but a low average loading. (CNO Ex. 3, p. 12; Tr. 4949, 4957, 5067.)

CNO also contends that a number of generating facilities included in MSU's pooling concept are not used and useful. In a classification study made by CNO, CNO Exhibit 7, 23 units listed by MSS as intermediate are identified as projected to be idle or have very low capacity factors in 1985. (CNO Ex. 4, pp. 21-22.) Also, CNO Exhibit 7 compares capacity factors and average loadings. Based upon its criteria of use, only 13 of 75 units projected for Middle South's system in 1985 would be classified as intermediate. the remaining units would be classified as base load or peaking units, or considered unused and unuseful facilities for pooling purposes. CNO Exhibit 7 is based upon a PROMOD study projecting dispatch of generating units on the Middle South system for the period 1983 through 1990 (CNO Ex. 4, p. 21). PROMOD is a proprietary, probabilistic production costing computer program leased by MSS from Energy Management Associates. PROMOD is used to simulate the economic dispatching of all units throughout the Middle South System based on, *inter alia*, forecasted fuel prices, loads and generating unit characteristics. (Tr. 1666-67).

MSS controverts CNO's reclassification proposal on the basis that it is overly subjective, only vaguely explained, unsupported by consistent logic and contrary to the established ratemaking principle that a generating facility need not achieve a certain capacity factor to be considered used and useful (MSS Initial Br., p. 56).

MSS persuasively argues that CNO's classification scheme depends on a subjective evaluation of what units should be intermediate, since no definition is given for what constitutes "a relatively high capacity factor but a low average loading" (MSS Initial Br., p. 57). In other words, CNO does not specify what criteria should be employed to determine whether a unit has a "relatively high" capacity factor in relation to a "low" average loading. In this regard, the CNO classification is vague and it would be possible for a unit to be intermediate one year and base load the next depending on the definitions of "relatively high" and "low."

Further, although CNO Exhibit 7 sets out specific classification zones, the boxed-in areas are placed on the exhibit to make CNO's subjective determinations for a particular time period more "discernible," not specifically to classify units (Tr. 5073-5074). In addition, as the boxes are drawn on CNO Exhibit 7, MSS points out that it could reasonably be assumed that a nuclear plant with a 25% capacity factor and a 100% average loading would be classified as a peaking plant or that a nuclear or coal unit with a 35% capacity factor and a 70% average loading could be regarded as an intermediate unit (MS Initial Br., p. 58). To avoid this, CNO admitted it would make *ad hoc* adjustments to classify these plants as base load (Tr. 5072-74). Such *ad hoc* adjustments represent a basic flaw in CNO's approach and show its inherent subjectivity.

Moreover, various units were classified as unused and unuseful by CNO based upon PROMOD, a simulated probabilistic economic dispatch study showing that the units

will not run in 1985. However, MSS rebuts this by noting that the probability that units will run is higher n reality than it is from an examination of a mathematical projection (Tr. 2041).

In addition, CNO agrees that all the units it classified as unuseful can act as reserves in 1985 to take care of unexpectedly high loads or forced outages of other units (Tr. 5068). Accordingly, the Commission decision in *Delmarva Power and Light Company*, 25 FERC ¶61,022 (1983) would apply. There, the Commission held that units which are used for peaking and which stand ready to meet the system's demand when needed are used and useful, and it noted that whether these units actually operated during the test period is irrelevant. The Commission also found that peaking units are considered as generation when determining reserve margins and system capacity, so that their actual usage during the test period is not determinative of whether they are used and useful. *Id.* at p. 61,120.

MSS points out that it has defined its coal and nuclear units as base load because they are operated at or near full load capacity because of their low fuel costs, while the oil and gas-fired units are classified as intermediate units because of their relatively high fuel costs (MSS Ex. 17, p. 73). MSS correctly asserts that this classification is a generally accepted approach (MSS Initial Br., p. 57). It is clear that the high fuel costs of oil and gas-fired units make it economically unfeasible to use these units as base load, whereas the low fuel costs of coal and nuclear make such units the reasonable choice for generating base load power.

In view of the above analysis, the CNO classification proposals must be rejected as subjective, not fully defined and contrary to Commission precedent on what plant is used and useful. On the other hand, MSS's approach is generally accepted and results in a reasonable categorization of base load and intermediate facilities. Therefore,

the MSS classification of generating units is hereby approved.

D. Treatment of Administrative and General Expenses

Service Schedules MSS-1, MSS-2 and MSS-4 have pricing formulas that include a designated OM component, which allocates operation and maintenance expenses and administrative and general (A&G) expenses attributable to the production and transmission functions of the owning MSU operating company. A&G expenses can generally be described as the overhead of the operational expenses of utilities (CNO Ex. 3, p. 19). The A&G expenses are not directly traceable to a particular investment and MSS spreads these costs among utility functions according to a labor ratios approach.

CNO recommends the exclusions of all A&G expenses from the formulas (CNO Ex. 3, pp. 24, 56). CNO also takes the position that, even if MSS may collect some A&G expenses through the system pool, the proposed method of labor ratios is inappropriate (CNO Ex. 3, pp. 20-22). CNO contends that application of a labor ratios allocator for A&G is not proper in the context of reserve equalization. CNO alleges that a reserve equalization study should concentrate on incremental costs, instead of fully allocated costs associated with A&G expenses for the intermediate generating units. (CNO Initial Brief, p. 86.) Since A&G expenses are to a large extent fixed costs, CNO argues that they would have been incurred with or without the system pool. As a result, CNO reasons, A&G expenses should not be subject to equalization by the pool. (CNO Ex. 3, pp. 21-22.) CNO also notes that MSS concedes that some of the A&G expenses are not necessarily associated with pooling activities (Tr. 2051-55).

Further, CNO avers that the application of the labor ratio allocator to reserve-related A&G expenses produces uneven results between companies from one year to the next (Tr. 2043-45). For example, NOPSI's overall A&G increased 12.8% from 1980-81 while the amount of its A&G

allocated to the pool rose 55.2% for that period (CNO Ex. 3, p. 25).

In addition, CNO contends that, although some A&G expense may be incurred in the pool operation, a competent study would show that expense to be minimal in amount. Moreover, CNO claims that such a study would show that the A&G related to pooling operations would basically be equal or a "wash" of expenses between the operating companies. (CNO Initial Br., p. 88, CNO Ex. 3, p. 26.)

MSS opposes CNO's recommendations on A&G expenses. MSS points out that labor ratios allocation has previously been approved for MSS pooling operations by a ruling of the Presiding Judge in *Middle South Services, Inc.*, 13 FERC ¶63,032, at p. 65,112 (1980). Further, in *Middle South Services, Inc.*, 16 FERC ¶61,101, at pp. 61,219, 61,224 (1981), the Commission approved expansion of the automatic clauses of the cost of service rate to cover A&G expenses. Implicitly, therefore, the Commission sanctioned the practice of allocating A&G expenses under the MSS pooling agreement.

Moreover, MSU presents the following cogent assessment. The MSU operating companies have both retail and non-affiliated wholesale customers, in addition to engaging in pool transactions with every other MSU operating company pursuant to the 1982 System Agreement. If A&G expenses are not allocated under the 1982 System Agreement, then each company's A&G expenses will be recovered totally from the company's retail and non-affiliated wholesale customers (MSS Ex. 17, p. 75). Since even CNO agrees that some A&G expense may be reasonably incurred in the pool operation (CNO Ex. 3, p. 26), MSS contends that retail and wholesale customers should not be required to pay all the A&G costs. In addition, MSS properly notes that the fact that fixed A&G costs would be incurred whether or not there was a system pool, is

no reason to exclude A&G costs from pool transactions. Since the companies will still incur A&G expenses with or without any particular retail or wholesale customer or customers being served, it is just as logical to exclude A&G costs from the rates of such customers. (MSS Initial Br., pp. 61-62.) This would be inappropriate and it is likewise unwarranted to exclude A&G costs from pooling transactions. Rather, MSS correctly argues that it is more reasonable to spread A&G expenses among all types of service rather than arbitrarily to relieve pooling exchanges from A&G responsibility since its incremental contribution to total A&G costs of a company is hard to quantify (id., p. 62).

Overall, it must be concluded that MSS is warranted in allocating A&G expenses to pool transactions and that its approach of using labor ratios to do so is a generally accepted procedure. Therefore, MSS's allocation of A&G expenses is approved.

E. Service Schedule MSS-3 Adder

Service Schedule MSS-3 of the 1982 System Agreement contains provisions governing the exchange and pricing of energy among the MSU operating companies. Pursuant to Service Schedule MSS-3, energy is allocated on an hourly basis from the lowest cost sources, first to the loads of the companies owning the sources and secondly to the pool. The company that supplies energy to the pool is reimbursed for the current estimated cost of fuel, plus an adder determined by Section 30.08(f) of Service Schedule MSS-3. The MSS-3 adder is designed to recompence the producing company for the incremental operating and maintenance costs associated with the production of additional energy (CNO Ex. 3, p. 51).

CNO objects to the MSS-3 adder and recommends that it be deleted pending a study to determine its proper level. CNO does not contest the theory underlying the adder but asserts that the MSS pricing is not in accordance with the

theory (CNO Ex. 3, pp. 51-52). CNO contends that MSS has provided no cost justification for the adder. In particular, CNO avers that there is no cost support for the 15 mills used as the constant in the indexing formula used to compute the adder. (CNO Initial Br., p. 84; CNO Ex. 3, pp. 51-55.) As a result, CNO argues that MSS has not sustained its burden of proof to show that the adder provision is just and reasonable.

MSS, in rebuttal, points out that the costs to be recovered under the adder are difficult to quantify by their very nature since incremental operating and maintenance expenses cannot be measured with enough accuracy to develop strict cost support. MSS notes that one of the difficult-to-quantify costs occurs when an operating company schedules maintenance on units differently than it would were it not participating in the pool. A deferral of maintenance to accommodate the overall interest of the pool could produce an increment of wear and tear on a unit that would not otherwise be experienced. (MSS Ex. 17, p. 78.)

Section 30.08(f) of Service Schedule MSS-3 contains the algebraic formula of the adder. The adder produces a charge of .6101 mills/kWh for June 1, 1982 to May 31, 1983 and was expected to produce a charge of .6630 mills/kWh from June 1, 1983 to May 31, 1984. (MSS Ex. 12.) Therefore, MSS contends that the adder appears reasonable when compared with percentage adders allowed in rate schedules for transmission services or third-party resales. Under Section 35.23(e) of the Commission's Regulations on Rate Schedules, 18 C.F.R. §35.23(e), no cost support is required if the percentage adder does not produce more than 1.0 mill/kWh. Moreover, MSS points out that, in Order No. 84, *FERC Statutes and Regulations, Regulations Preambles 1977-1981,* ¶30,153, at p. 31,031, wherein Section 35.23 was established, the Commission set out that an adder is intended to recover "unquantifiable or expensive-to-quantify incremental energy costs . . . By

definition, percentage adders are a ratemaking convenience for recovering costs that cannot otherwise be easily demonstrated." MSS also relies on *Ohio Edison Company,* 23 FERC ¶61,344, at pp. 61,749-50 (1983), where the Commission approved the use of an uncapped 10 percent adder to recover hard-to-quantify, incremental operating and maintenance expenses even though strict cost support was not furnished.

On analysis, the level of the MSS-3 adder appears reasonable and there is adequate justification for MSS not providing definite cost support for it. Although not specifically quantified, the operation and maintenance costs are being incurred and the operating companies should be allowed to recover them through an adder. Moreover, the MSS-3 adder appears to be conceptionally the same as the percentage adders allowed by Section 35.23 of the Commission's Regulations, since both seek to recover hard-to-quantify, incremental costs. Therefore, strict cost support for the MSS-3 adder will not be required herein, particularly since the adder does not exceed 1 mill/kWh. With this evaluation, it can be concluded that the MSS-3 adder is just and reasonable. It is, therefore, approved.

F. Service Schedule MSS-1 Adder

Service Schedule MSS-1 of the 1982 System Agreement contains an adder which is designed to give credit to the operating companies, for reserve equalization purposes, for the value of capacity backed by reserves, which is purchased from non-affiliated utilities. The adder is calculated in accordance with an algebraic formula set out in Section 10.02(c) of Service Schedule MSS-1. (MSS Ex. 6, pp. 1, 10).

To place this in context, the definition of Company Capability must be reviewed. Under Section 10.02(a)-(f) of Service Schedule MSS-1, Company Capability is set out as consisting of: (1) the MW produced by a company's available generating units; (2) the MW a company purchases

without reserves from other affiliated or non-affiliated utilities; and (3) the MW of a company's firm purchases, that is, those backed by reserves, from non-affiliated utilities, plus the MSS-1 adder applicable to such firm purchases. The purpose of the MSS-1 adder is to give credit to the operating company for reserves provided by the non-affiliated utility. (MSS Ex. 17, p. 79; Tr. 0729.)

CNO recommends deletion of the MSS-1 adder from the definition of Company Capability (CNO Initial Br., p. 74). CNO contends that the adder treats different capacity purchases unevenly, distorts reserve equalization payments by dealing with capacity that does not exist, and provides an incentive for the operating companies to make unnecessary firm purchases from non-affiliated entities at a time when the Middle South system is about to experience substantial excess capacity. (CNO Ex. 3, pp. 35-38; Tr. 4964-66.) CNO also complains that the adder is discriminatory since it only applies to purchases of firm capacity, with no corresponding subtraction of an adder for firm sales by the operating companies to foreign buyers. CNO suggests that, if the adder is meant to prevent an operating company from paying twice for reserves, there should be a corresponding subtraction to prevent an operating company from being paid twice when it sells capacity with reserves. (CNO Initial Br., p. 72.)

CNO rests it claim that the adder treats different capacity purchases unevenly on the fact that the formula is not fixed but works on a sliding scale. Therefore, on the only foreign purchase currently being made, 150 MW by AP&L, the adder credited to AP&L is 100 MW (MSS Ex. 16, Exhibit XI, Sheet 1 of 3), or 67% of the purchase. If the purchase were 2000 MW, the adder would be 2261 MW or 113% of the contract amount and would result in the purchaser getting credit for more than double the purchase (CNO Ex. 3, p. 36; tr. 2089-91). CNO further notes that the adder formula fluctuates depending on the percentage of reserves on the Middle South system. With an

increase in reserves, the adder is increased and CNO avers that this results in different treatments for the same purchase. (CNO Initial Br., p. 71.)

CNO also argues that the adder results in distortions since it is based on reserves that do not actually exist on the Middle South system. CNO alleges that the adder is calculated in relation to the Middle South system's reserves and not on the reserves of the foreign seller, so it does not reflect the extra price, if any, the purchasing company pays to obtain the reserves and, thus, is not cost-supported. (CNO Initial Br., pp. 71-72.)

CNO's incentive argument is grounded on the rationale that giving an operating company an added credit for firm purchases from outside the system, will encourage such purchases, as will the sliding scale of the adder formula that gives greater credit for larger purchases (CNO Initial Br., pp. 72-73).

In rebuttal, MSS counters that the MSS-1 adder serves the legitimate purpose of giving credit to the purchasing Middle South company for reserves provided by the non-affiliated selling company (MSS Ex. 17, p. 79; Tr. 2097). MSS reasons that additional credit is warranted for a purchase with reserves because a purchase of 150 MW which is supported by the selling party's reserves is more valuable than a purchase of 150 MW of capacity which is not backed by any reserves. As a result, MSS asserts that it is reasonable to give credit by means of an adder for purchases with reserves. (MSS Initial Br., pp. 67-68.)

Moreover, MSS notes that a credit for a 150 MW purchase in the 100-115 MW range is conceded by CNO to be "somewhat reasonable" (Tr. 4965). In addition MSS persuasively argues that the adder does not produce any inappropriate incentive to pursue foreign purchasers since the only current such purchase expired at the end of 1983 and the operating companies are not seeking other firm

purchases from non-affiliated utilities (MSS Initial Br., pp. 68-69; Tr. 2097).

MSS also effectively replies to the CNO discrimination argument by pointing out that firm sales by an operating company increases the company's Load Responsibility, thereby increasing its proportionate share of reserves, which results in a reduction of the company's reserves equalization receipts and an increase in its payments. Therefore, a capacity adder is unnecessary for firm sales by an operating company since what is being affected is Loan Responsibility, not capacity. (MSS Reply Br., pp. 6-7.)

On analysis, the MSS Position on the MSS-1 adder is better taken and the adder will be approved. Despite possible fluctuations and the sliding scale, the level of the adder in its practical application is reasonable. The high level of reserves on the Middle South system make any substantial firm purchases must unlikely, so distortions such as a 2000 MW purchase are a *de minimis* risk. With regard to small firm purchases which might possibly occur in the future, the adder formula seems reasonable. Moreover, the high Middle South system reserves will operate to offset easily any minor incentive the adder credit affords to an operating company to make foreign firm purchases. Nor is there any inherent defect in treating the same purchase differently depending on the level of system reserves, when the underlying concept of the adder is taken into account. Further, since the adder from a practical standpoint achieves reasonable results (as demonstrated by the recent 150 MW AP&L purchase), cost support therefor from the selling utility need not be furnished, particularly since such data might be hard to secure and would result in unnecessary further expenses. Overall, therefore, use of the proposed MSS-1 adder is just and reasonable, and its inclusion in the 1982 System Agreement is hereby approved.

VI. Production Cost Allocation

A. Description of the Proposals

As discussed in the Overview, Section II, *supra*, three major proposals on production cost allocation were advocated by the parties at the hearing. These were: (1) the position of MSS and the Arkansas interests to adopt the 1982 System Agreement as filed; (2) the position advanced by the Staff, LPSC, and CNO that production costs should be equalized; and (3) the position advocated by MPSC that the participation unit concept be retained, with MSE becoming a party to the System Agreement and Grand Gulf becoming a participation unit. Since there are three separate production cost equalization proposals, that of the Staff, LPSC, and CNO, in all five production cost allocation methodologies are covered in the record. All five will be described in appropriate detail to elucidate the differences between the parties on this major issue.

1. The MSS Proposal

The MSS proposal, now advocated by AP&L and the Arkansas interests, seeks to have the 1982 System Agreement approved as filed. As can be seen from the description of the 1982 System Agreement in Section III, *supra*, this would result in equalization only of the costs of reserve capacity between the long and short companies. It does not provide for equalization of all capacity costs. (MSS Exhibit 17, p. 4; r. 1738-40). Also, energy costs are not equalized under the 1982 System Agreement. Rather, each company has the right to its own lowest cost sources of energy for the benefits of its customers, and only those sources of generation in excess of the companies' own requirements is made available to other companies under Service Schedule MSS-3 (MSS Ex. 1, p. 14; Tr. 1735). In essence, the 1982 System Agreement calls for equalization of the costs of reserve capacity only. Service Schedule MSS-1, which was designed to implement this concept, is entitled "Reserve Equalization."

The approach of the 1982 System Agreement is that each operating company shall bear the responsibility for the portion of total System Capability as its Company Load Responsibility bears to System Load Responsibility (Service Schedule MSS-1, §10.03). As discussed previously in Section III, *supra,* Company Load Responsibility is used to calculate a company's Capability Responsibility for purposes of determining the number of MW to be considered as an excess (long) or as a deficiency (short) for purposes of the 1982 System Agreement. Once it has been determined which companies are long or short, the 1982 System Agreement then uses the capacity costs of the intermediate generating units, that is the oil and gas fired units, to determine the amount of the payment to be made by the short companies to the long companies. The rationale behind use of the intermediate generating units is that these units are now used primarily to provide reserve power for the operating companies because of their fuel costs. Therefore, such units are appropriate for use in equalizing reserve capability. As mentioned previously, there is no provision for entitlement energy from the oil and gas units. Instead, the short companies are entitled to purchase energy at the exchange energy rate under Service Schedule MSS-3, which is the lowest cost energy available from the pool. Under this proposal there would be no partial or total production cost equalization. Also, since the units used for equalizing reserve capacity are the intermediate units, the proposed 1982 System Agreement is different from the 1973 System Agreement. The 1973 System Agreement used reserve equalization based upon the latest unit placed in service by the long company,which unit was designated the "participation unit." in addition, the 1973 System Agreement permitted proportionate energy entitlements to the short companies from the participation unit.

2. Equalization Proposals

a. The Staff Proposal

The Commission Staff proposes a modification of the 1982 System Agreement that would equalize the cost of base load generating facilities among the four MSU operating companies (Staff Ex. 2). Staff defines base load generating facilities as all coal and nuclear-fired units and would allocate to each operating company a share of such units determined by the ratio of each company's annual average load to the annual average load of the system. In addition, each company would receive its proportionate share of energy from each base load unit. An individual company would make payments to the pool or receive payments from the pool based upon the difference between the company's equalized cost and the actual cost of base load generation on its own system. (Staff Initial Br., pp. 120-21; Staff Ex. 1, p. 6.) The Staff does not propose to equalize the costs of generating units which are not base load facilities (Staff Ex. 1, p. 6).

Moreover, Staff proposes that the carrying charges for the base load units be levelized, to insure an equitable implementation of generation cost equalization. The purpose of levelization is to be fair to customers who have paid the high front-end costs associated with construction of on line coal and nuclear units and avoid the inequity of equalizing away those units now that they have been depreciated. Under a levelization methodology, a fixed amount is collected annually over the life of a unit, to recover return, depreciation, income taxes and a return on the difference between levelized and non-levelized costs. This latter return compensates for the fact that, in the first few years of the unit's life, the levelized cost is lower than the non-levelized cost, by paying for the time value of money not recovered under the levelized cost method. The levelized charge would be calculated based on the undepreciated cost of the unit, so customers who have paid

the high front-end costs will be repaid those costs, plus a return, over the remaining life of the unit. (Staff Initial Br., pp. 123-24; Tr. 4072-77, 4172-76, 4203-05.)

The Staff initially proposed a levelized costing method for all base load units (Staff Exhibit 35, Sch. 2) but conceded that it would not be necessary to utilize the levelized approach for Grand Gulf Unit I or for Independent Unit 2, since no customers to date have paid high front-end costs for those facilities as they are not yet in service (Tr. 3450-51). In addition, Staff agreed that it would not be necessary to levelize cost of Independence Unit I, since it came on line after the effective date of the 1982 System Agreement (Tr. 3451-52). Also, Staff concurs that White Bluff Units 1 and 2, which came on line in 1980 and 1981, were participation units until the 1982 System Agreement became effective, so levelization would be unnecessary for those facilities since all the operating companies paid the high front end costs associated with them (Tr. 3453-54). In addition, Staff concedes that it is unnecessary to levelize charges for AP&L's ANO Unit 2, because of the short time that unit was in service before the 1982 System Agreement went into effect and the fact that White Bluff has been the subject of a unit power sale by AP&L, which offsets the front-end costs paid by AP&L for ANO Unit 2 (Tr. 3462). In light of the above, Staff now advocates that only the costs of AP&L's ANO Unit 1 be levelized (Staff Initial Br., p. 125).

Staff also recommends that the costs for LP&L's Waterford 3 be increased to reflect the fact that LP&L's Waterford customers have already paid a portion of the construction costs for that unit through rates which include construction work in progress (CWIP) (Staff Ex. 1, p. 6).

Staff contends that its proposal is in accord with the objectives in Article III, §3.01 of the 1982 System Agreement, since it provides a basis for equalizing costs among the companies for facilities used for the mutual benefit of

all the companies. The rationale here is that all the units on the MSU system are operated for the benefit of the system as a whole and, therefore, the costs of the base load units should be equalized since the disparity in their costs causes the majority of the imbalance costs on the system. In addition, the Staff asserts that this will permit each company to have a proportionate share of base load units to serve its own customers, as provided for in Article III, §3.05 of the 1982 System Agreement. (Staff Initial Br., pp. 121-22.)

b. LPSC's Proposal

LPSC's equalization proposal is essentially similar to the Staff's but is broader. LPSC would have all production costs, excluding fuel, on the Middle South system combined and allocated to each operating company based upon that company's Capability Responsibility. As opposed to the MSS proposal, LPSC would substitute all production plant for what MSS would restrict to intermediate plant. LPSC would also include the demand cost portion of purchased power in the production costs to be equalized. In addition, under the LPSC proposal, a rate would be established to equalize all the energy costs per kWh. All fuel costs, including the energy cost portion of purchased power, would be totalled monthly and billed to each operating company on the basis of relative energy sales adjusted for distribution losses. This energy rate schedule would eliminate the need for Service Schedule MSS-3 and Service Schedule MSS-4 would be rendered moot since no unit power purchases would take place under LPSC's proposal. (LPSC Ex. 1, pp. 24-25.)

c. CNO's Proposal

While CNO, as discussed *supra*, advocated a variety of revisions to the 1982 System Agreement, its ultimate preferred position was that there be an equalization of production costs (Tr. 4941-42). CNO proposed that all nuclear

and coal-fired units be equalized in the same manner as recommended by the Staff. All other production plants, including peaking units, would be equalized on a two-part basis. Capacity costs of these other plants would be treated in the same manner as set out in Service Schedule MSS-1 of the 1982 System Agreement. Like the MSS proposal, this capacity equalization would not carry with it any right to energy from the equalized intermediate plants (intermediate having been expanded by CNO to include all production plant other than nuclear and coal-fired). Rather, the operating companies would draw energy in excess of base load (nuclear and coal) equalized energy requirements from the system pool. (CNO Ex. 4, p. 71.)

In addition, CNO recommends that a study be done to determine a method to repay AP&L customers for the high front end costs they have incurred with respect to the ANO nuclear units, and to repay LP&L's ratepayers for the cost of CWIP included in the rate base with respect to Waterford 3 (Tr. 4951). CNO, however, would not levelize the costs with respect for AP&L's base load units, but would credit AP&L's ratepayers with the difference between the cost per kW of the units that they had paid in previous years and the present cost per kW of the units, plus interest. After that, equalization would be on the same basis as the carrying costs paid by the operating companies. (Tr. 4952-54.)

3. MPSC's Proposal

MPSC has taken the position that the 1982 System Agreement should be rejected and that the 1973 Agreement, with its participation unit concept, be retained. In addition, MPSC would have MSE, the MSU subsidiary that owns the Grand Gulf nuclear facility, be required to sign the System Agreement. This would have the effect of making the Grand Gulf units participation units, since they are the only units owned by MSE. The net result of this would be that the Grand Gulf capacity costs, carrying with them

energy entitlements, would shift between individual companies as the companies became short or long. Therefore, Grand Gulf's capacity and energy costs would be paid for by the short companies. Since MP&L is a long company and is expected to remain so until the 1990's, MP&L would avoid responsibility for Grand Gulf for that period. (MPSC Ex. 1, pp. 17, 18.)

B. The Operation of the Middle South System

To determine which of the production cost allocation proposals should be adopted, it is first in order to review in appropriate detail the operation of the Middle South system.

MSU is a registered public utility holding company under the Public Utility Holding Company Act of 1935 (PUHCA), 15 U.S.C. §79 *et seq.* The Middle South system is made up of the parent holding company, MSU, and the following wholly-owned subsidiaries: The four operating companies, AP&L, LP&L, MP&L and NOPSI; the separate generating company, MSE, the owner of the Grand Gulf nuclear stations; MSS, the corporate service company; and System Fuel, Inc., a fuels procurement company. MSU was established in 1949, when it replaced Electric Power and Light Corporation which had owned the four operating companies since the 1920s, *see In the Matter of Electric Power and Light Corporation,* 29 SEC 52, 55 (1949).

MSU owns all the common stock of its subsidiaries, including the four operating companies. However, each operating company has a separate board of directors, which are selected by MSU, the sole stockholder. These boards select the executive officers of the companies who are responsible for the day-to-day operations of the individual companies (Tr. 514, 1067-78, 2467-72.) The Middle South system does have various common officers and directors. The Chairman and Chief Executive Officer of MSU is a member of the board of each operating company, is President and a Director of MSE, and is Chairman, Chief Ex-

ecutive Officer and a Director of MSS. Also, the Chief Executive Officers of the operating companies are members of the board of MSU. In addition, other members of the MSU board are members of the board of individual operating companies. Further, LP&L and NOPSI have a number of common officers and the Board of Directors of MSS is made up of the Chief Executive Officers of MSU, System Fuel, Inc., and the four operating companies. These individuals also make up the Board of Directors of MSE. (Tr. 2467-72; CNO Ex. 26; MSS Ex. 53; SEC Form U5S.)

Prior to the formation of MSU in 1949, the operating companies were already interconnected and had system-wide planning, *In the Matter of Electric Power and Light Corporation,* 29 SEC 52, 63 (1949). As noted above, MSU is now operated as an integrated electric utility system under the PUHCA. Operation of all generation units are controlled and dispatched by the system through the central dispatch office operated by MSS in Pine Bluff, Arkansas (Staff Ex. 16). The transactions among the operating companies have been controlled by some form of System Agreement since 1951, almost from the time of MSU's inception. As discussed in Section III, *supra,* there had been three System Agreements in all, the 1951, the 1973 and the 1982 versions.

While the System Agreement has been revised, the basic structure of the arrangements has remained intact. Each of the three System Agreements has provided for joint planning among the operating companies through the Operating Committee, and for construction of generating facilities that would result in meeting loads with less aggregate capacity (APSC Ex. 3, p. 1; APSC Ex. 25, Art. III, § 3.05; MSS Ex. 2, Art. III, § 3.08). The Agreements have also provided for coordinated construction planning to enable the operating companies to build units of larger sizes and units at strategic places (APSC Ex. 3, p. 1; APSC Ex. 25, Art. III, § 3.02; MSS Ex. 2, Art. III. § 3.04). In addition, the 1951 and 1973 Agreements specify

that, in the interest of economy and efficiency, generating capability in excess of normal requirements could be installed by one company for the use and benefit of the customers of another company (APSC Ex. 3, p. 2; APSC Ex. 25, Art. IV, § 4.01). While that specific provision is not included in the 1982 System Agreement, the 1982 Agreement does set out that cost will be equalized among the operating companies for facilities that are used for the mutual benefit of all the companies (MSS Ex. 2, Art. III, § 3.01). The 1982 System Agreement also provides that there shall be equalized among the companies the cost of any capability that an individual operating company has in excess of its Capability Responsibility as a result of installation of facilities in accordance with the provisions of the generation addition plan (MSS Ex. 2, Art. IV, § 4.01).

The System Agreements, therefore, clearly permit and encourage, for efficiency, reliability and other economies of scale, that the individual companies from time to time build larger facilities than are necessary to meet their own native load, to benefit all the generating companies by having lower costs and greater reliability. Subsequently, the building company is to grow into the facility as its load increases. As will be seen from the history of the generation additions discussed *infra*, this rationale was generally implemented in connection with the Middle South system generation additions during the period from the inception of Middle South Utilities until the 1982 System Agreement was put into effect.

The Operating Committee's functions include the day-to-day administration of the System Agreement and control of the central dispatch system (APSC Ex. 3, p. 3; APSC Ex. 25, Art. IV, § 4.08, Art. V, § 5.06; MSS Ex. 2, Art. IV, § 4.08, Art. V, § 5.06). In addition, the Operating Committee performs studies to determine the need for new generation and transmission facilities (APSC Ex. 3, p. 5; APSC Ex. 25, Art. IV, § 4.06, Art. V, § 5.06(a) and (i); MSS Ex. 2, Art. IV, § 4.06, Art. V, § 5.06(b) and

(j)). Based on the generation addition studies, the Operating Committee assigns the installation of generating units to the individual operating companies (APSC Ex. 3, p. 5; APSC Ex. 25, Art. IV, § 4.01, Art. V, § 5.06(b); MSS Ex. 2, Art. IV, § 4.01, Art. V, § 5.06(b)).

Moreover, the Operating Committee, which is made up of members designated by the Chief Executive Officers of the operating companies and MSU, now votes with 80% of the control being vested in the operating company representatives in proportion to the individual company's Responsibility Ratio and with 20% of the vote being controlled by MSU. The 1973 System Agreement had provided for action by a two-thirds majority vote but this was changed when LP&L's load became large enough that LP&L could, on its own, block action by the Committee. Under the present arrangement, a simple majority is sufficient to allow the Committee to take action. (APSC Ex. 25, Art. V, §§5.01 and 5.04 MSS Ex. 2, Art. v, §§5.04; Staff Ex. 13.) This change means that the Operating Committee can make decisions against the wishes of at least one and, depending upon which companies are involved, sometimes two operating companies.

The operation of MSU as a power pool is aptly described in a 1981 FERC report, Power Pooling in the United States, at p. 127 (CNO Ex. 24, p. 127):

> Because of its electrical size and strongly integrated planning and operations, MSU is able to use the full range of power supply options available to the electric utility industry. The pool can select what it considers to be the optimum combination of capacity resources by size and fuel type to minimize both investment and operating costs. Operating economies are secured by centralized dispatch and by exchanges with other utilities within the SPP Region and in the Southeast Region. The external coordination includes short-term capacity exchanges, seasonal diversity exchanges,

> economy energy interchanges, and coordination of daily operations. It appears that the MSU companies are capturing most of the economic and reliability benefits of power pooling. Because of its size and efficiency, coordination with MSU should be pursued by the smaller independent systems in its area as the key to securing the economies of scale.

As can be seen from the above description of the operation of the Middle South system, it is a complicated and sophisticated arrangement that has been working efficiently on a pool basis since 1949. Next, it is important to look at the history of generation additions on the system and the manner in which these additions were made.

C. The History of Generation Additions

The history of generation additions on the Middle South system shows that, during the 1950's, generating facilities were located in Louisiana to reduce generation costs, since abundant supplies of inexpensive natural gas existed in Louisiana. For example, during 1956–1960, AP&L had insufficient capability to meet its load and purchased substantial quantities of energy from LP&L under the 1951 System Agreement (LPSC Ex. 12, p. 1). This situation also occurred in the 1960's, since AP&L had insufficient capacity to meet its load, even with purchases, in 1964, 1965-67 and 1969 (LPSC Ex. 12; Tr. 1083-85). This trend continued into the 1970's, when AP&L's peak load often exceeded its own generating capability. Even with purchases, AP&L had insufficient capabilities to meet its native load in five years during the 1970's and, in none of the years in the 1970's did AP&L have sufficient reserves (Tr. 6541-42). Similarly, Arkansas Missouri Power Company (Ark-Mo), which is now merged with AP&L, did not have capacity sufficient to meet its load during the 1970's (LPSC Ex. 13). As a result, during the 1970's, AP&L was consistently short and purchased capacity, primarily under the participation unit arrangement, from the other oper-

ating companies. During the same period, LP&L's own generating capability generally exceeded its peak load, as did the generating capability of MP&L and NOPSI. (Tr. 551-55, 769-70, 802, 812-13, 817-18, 1089-96, 2249, 2564-74, 4159-60; OCC Ex. 49, p. 912; OCC Ex. 50, p. 462; LPSC Ex. 76, pp. 943, 947; LPSC Ex. 81, pp. 817-18; LPSC Exs. 12-18, Ex. 79, and 80; MPSC Ex. 4; Tr. 2564-74.)

The oil and gas units that went into service in the Middle South system prior to 1970 was relatively inexpensive, less than a $100 per kW and, each of the operating companies added major oil and gas fire units in the late 1960s and early 1970s, as can be seen upon the following chart, which is based upon data from LPSC Exhibit 83:

Company	*Unit*	*Year*	*MW*	*$/kW*
AP&L............	Ritchie 2	1968	544	79
	Lake Catherine 4	1970	547	71
LP&L............	Little Gypsy 2	1966	436	58
	Little Gypsy 3	1969	573	70
	Ninemile Point 4	1971	748	77
MP&L	Wilson 1	1967	550	97
	Wilson 2	1971	771	93
NOPSI...........	Michoud 3	1967	548	68
	Wilson 2	1971	771	93
NOPSI...........	Michoud 3	1967	548	68

In the late 1960s and early 1970s, the system embarked upon a program of generation expansion that included, *inter alia,* the construction of nuclear and coal-fired units in an effort to lower costs and to achieve economies of scale. Since AP&L had been a traditionally short company and one with poorest access to natural gas supplies, it was the first company assigned to construct a nuclear unit, ANO 1. ANO 1, an 836 MW plant, went on line in 1974 at an installed cost of about $232 million (Staff Ex. 2,

Sch. 4, Sheet 4). In addition, as part of this major expansion, LP&L brought on line Waterford Units 1 and 2, which consist of 822 MW of oil-fired capacity and MP&L added 760 MW of oil-fired capacity in Andrus Unit 1. While the capacity costs of ANO 1 ($276 per kW) were almost double that of the oil-fired Waterford and Andrus Units ($150 per kW), there was not a significant difference in the initial "busbar", or total generation, costs of these units in 1975, because of the lower fuel costs associated with the nuclear plant.

Again in the early 1970s, AP&L was assigned the responsibility to construct a second nuclear unit, ANO 2 (Tr. 1531). Within the same time frame, LP&L was assigned the responsibility to construct the nuclear unit known as Waterford 3 (Tr. 1531, 1565). And, the Grand Gulf project was being initiated during this period. The chronology of Grand Gulf is as follows:

In September 1970, the Operating Committee requested that MSS invite bids for two additional generators. MP&L at that time indicated that it was willing to install the next nuclear unit and there was discussion regarding the construction of one nuclear facility for 1978 and another for 1979. (LPSC Ex. 37, p. 5; MSS Ex. 38, p. 3; Tr. 1528-30.) MP&L's interest in installing a nuclear unit was an indication that it wanted to diversify its fuel mix (Tr. 1531).

NOPSI, in February 1971, presented a study to the Operating Committee showing its interest in constructing a nuclear unit for 1978 operation. This NOPSI proposal to build a 1978 nuclear unit was based both on its load forecast and on its interest in diversifying its fuel mix. (Tr. 1529-33.)

In July 1971, the Operating Committee recommended that the system commit for three nuclear units, one for 1979, one for 1980 and one for 1981, although no commitment ever ended up being made for the 1981 unit.

There were, however, commitments made for the two other nuclear units but the timing had been moved back from the original 1978 and 1979 periods to 1979 and 1980. (Tr. 1529, 1534.) And, in July 1971, it was agreed by the Operating Committee that MP&L would build the nuclear unit to come on line in 1979 and NOPSI would build the one for operation in 1980. Both units were projected to be 1250 MW. (Tr. 1534, 1538-41.)

MP&L then proceeded in September 1971 to file for a license from the Atomic Energy Commission to build Grand Gulf Unit 1 (Tr. 1564-65). However, NOPSI conducted a study of the cost of constructing the nuclear unit to be built by it. That study showed there would be a substantial cost penalty associated with the proposed site for the nuclear unit in eastern New Orleans, and NOPSI informed MSS by letter in August 1972 that it would not proceed with the unit. After it was determined that it would not be economic to construct a nuclear unit in NOPSI's territory, it was recommended at the September 1972 meeting of the Operating Committee that this unit also be located in Mississippi as Grand Gulf Unit 2. (LPSC Ex. 40, p. 4; LPSC Ex. 41, pp. 5,7; Tr. 1541-42, 2537-38.)

At that September 1972 meeting of the Operating Committee, MP&L indicated it would have difficulty financing one nuclear unit, let alone two (LPSC Ex. 41, p. 5; Tr. 1542, 1560). Without financing from the system, MP&L would not have been able to finance even a single unit in the 1200 MW class, such as Grand Gulf Unit 1 (LPSC Ex. 41, p. 5; Tr. 1560-62), but MP&L did indicate that it was willing to undertake construction and management of a second unit at Grand Gulf if joint financing by the other operating companies could be arranged (LPSC Ex. 41, p. 7; Tr. 1545-47). MP&L did not volunteer for the second unit at Grand Gulf and it was understood by the Operating Committee in September 1972 that, if the Grand Gulf units, particularly the second unit, were to be completed, a generating company or joint ownership would be necessary

(Tr. 1543). MP&L was, therefore, asked in September 1972 by the Operating Committee to continue planning activities for both Grand Gulf units, even though other operating companies might become involved with these units later (LPSC Ex. 41, p. 7).

As noted above, in September 1972, consideration was being given by the Operating Committee to joint ownership by the operating companies or to formation of a generating company to own and finance Grand Gulf (Tr. 1546-47). After a study of these two alternatives by the financial departments of the MSU companies, it was decided by the Chief Executive Officers of the MSU companies to use a generating company rather than joint financing (Tr. 1556). As a result, in the 1973-74 time frame, MSE was formed as a generation subsidiary of MSU to own and finance Grand Gulf Units 1 and 2 (Tr. 1557-58, 2434), with MP&L serving as MSE's agent for construction and operation of the facility (Tr. 2434, 2548). It should also be noted that, in 1974, the intent at one point was for the generating company, MSE, to own all base load capacity, except for certain specific units under construction at the time. This would have resulted in base load equalization at some juncture but it was never put into effect because of financial restrictions placed on MSE by its creditors. (Tr. 2595, 2701.)

Due to licensing delays, neither Waterford 3 nor Grand Gulf I has yet come on line, but ANO 2 began commercial operation in 1980 with a capacity of 858 MW at an installed cost of about $608 million (Staff Ex. 2, Sch. 4, Sheet 4).

The Middle South generation expansion program also resulted in AP&L adding two coal-fired units, White Bluff Units I and 2, of which AP&L share is 930 MW. In addition, AP&L constructed a coal unit, Independence I, in 1983 and has under construction Independence 2, another coal unit. These Independence units will add 260 MW

apiece to AP&L's capacity. (Tr. 2531, 2615.) The reason that AP&L was selected to construct the four coal units was that, in the late 1960s and early 1970s, AP&L began to lose long-term gas contracts. Also, AP&L is located closer to sources of coal supply than the other MSU operating companies (Tr. 2531) and, as noted above, AP&L had been short in terms of its capacity compared to its load requirements. Also, the companies in Louisiana and Mississippi had a more favorable gas and oil fuel supply situation than Arkansas.

Under current circumstances, although the System Agreement provides that each of the operating companies should have an appropriate share of base load nuclear and coal generation, there is a imbalance on the system in this regard. Not including an offset of one minor 208 MW purchase of coal capacity by MP&L from AP&L that just recently occurred, the present mix of base load generation on the system is as follows: AP&L, 2624 MW LP&L, O MW MP&L, O MW and NOPSI, O MW (Staff Ex. 2, Sch. 4, Sheets 4-7). This picture will be altered when the 1104 MW Waterford 3 Unit comes on line and the 1125 MW Grand Gulf I goes into operation. These are projected to be on line during 1985, with a capacity cost of about $3 billion for each of these nuclear units. This results in a cost of over $2500 per kW for Waterford 3 and Grand Gulf 1. (MSS Ex. 67; Tr. 4125-26; MSU SEC Form U-1, pp. 12, 15, May 31, 1984.) These two units will cost approximately as much as the entire net plant in service in 1981 on the whole Middle South system, including production, transmission distribution and general plant (Tr. 3489, 3552-54). The Waterford 3 and Grand Gulf 1 nuclear units will provide about 13% of system capacity, but will account for over 70% of the total system investment in production plant (CNO Ex. 4, p. 24; Tr. 3489, 3552-54). The 70% plus figure is calculated using current Waterford 3 and Grand Gulf 1 costs in relation to Table 3 on page 24 of CNO Exhibit 4.

In Middle South's current projections, no major additions, except for the second coal-fired Independent Unit 2 that will be jointly owned by AP&L (250 MW) and MP&L (208 MW), are planned to be added to the system until the 1990s. Also, Independence Unit 2 is expected to come on line at less than $500 per kW. In 1990, Grand Gulf Unit 2 is projected for completion. Further, LP&L is scheduled to construct and bring on line the first of two 800 MW coal-fired units at Wilton in 1992, at an estimated cost of $1200 per kW, with NOPSI jointly owning 10% of each unit. AP&L also currently is planning to construct additional coal-fired capacity, the Alec plant, to go into operation in the mid-1990s (LPSC Ex. 73).

The Middle South actual and projected base load generation additions can be summarized as follows:

Co.	*Unit*	*Year*	*MW*	*$/kW (Rounded)*	*First Year ¢/kWh (Rounded)*
AP&L	ANO 1 & 2	1974/80	1694	500	3-4
	White Bluff 1 & 2	1980/81	930	370	4
	Independence 1	1983	260	600	4-5
	Independence 2	1985	260	500	—
	Alec	1995	200	2,600	—
LP&L	Waterford 1&2	1975	822	150	3
	Waterford 3	1985	1104	2,500	15+
	Wilton 1	1992	640	1,200	—
MP&L	Andrus 1	1975	760	150	3
	Independence 1	1983	208	600	4-5
	Independence 2	1985	208	500	—
NOPSI	Wilton 1	1992	160	1,200	
MSE	Grand Gulf 1	1984	1125	2,600	15+
	Grand Gulf 2	1990	1125	—	—

(Tr. 578,855, 1458, 1923, 2586, 2608, 2611-15, 2620-33, 2778, 3466, 3483-4, 4130, 6158-9, 6179, 6271-2; LPSC Ex. 78, p. 1306; APSC Ex. 30; CNO Ex. 50, p. 40; Staff Ex. 2, Sch. 4; Staff Ex. 3, Sch. 1; LPSC Ex. 83; MSU 1983 SEC Form 10-K, Att. 3.)

The above review of generation additions makes clear that the very large costs of the two nuclear units to be brought on line by LP&L (Waterford 3) and MSE (Grand Gulf I) have caused the requests for revision of the 1982 System Agreement that would incorporate into it some form of equalization of production costs among the operation companies, rather than the current format that only equalizes reserve capacity. The Staff and the Louisiana interests seek to justify cost equalization based to a large extent upon the integrated operation of the Middle South system. They claim that, since it is a single, integrated electrical system, production costs should be shared equally. They also contend that the prior System Agreements had as a goal the rough equalization of production costs, and in fact did accomplish this objective, whereas the 1982 System Agreement will cause such an imbalance that it will result in inequities and in the objectives of the System Agreement not being achieved.

Opposed to the equalization proposals are the Arkansas interests, who claim that the current arrangements under the 1982 System Agreement represent a continuation of operations under the System Agreements, where, from time to time, an operating company with excess capacity is long and becomes short as its load increases and generation facilities assigned to its sister companies are added. They also assert that the cost disparities that will result when the two large nuclear plants come on line are not of such magnitude that inequity will result to the Louisiana and Mississippi ratepayers. Further, the Arkansas interests raise objections to equalization based on a variety of other arguments. These alleged impediments to equalization can now be reviewed.

D. Alleged Impediments to Equalization

1. The Mobile-Sierra Doctrine

APSC (APSC Initial Br., pp. 75-81) and Arkansas Industries (Arkansas Industries Initial Br., pp. 40-42), assert

that the 1982 System Agreement is entitled to protection under the *Mobile-Sierra* doctrine as a voluntary contract entered into by the MSU subsidiary companies, which can be abrogated only in circumstances of unequivocal public necessity. In this latter regard, they rely on *Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968). APSC further contends that the 1982 System Agreement is entitled to *Mobile-Sierra* protection even before its approval by the Commission, citing *Borough of Landsdale, Pa. v. F.P.C.*, 494 F.2d 1104, 1113 (D.C. Cir. 1974).

The *Mobile-Sierra* doctrine arises out of two companion cases decided in 1956 by the Supreme Court, *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) *(Mobile)* and *F.P.C. v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) *(Sierra)*. The *Mobile* case dealt with the Commission's review authority under Sections 4(c), (d) and (e), and 5(a) of the Natural Gas Act (NGA), 15 U.S.C. §717, *et seq.* The case discusses in detail the notice and hearing procedure and the suspension and refund powers of the Commission under Section 4, plus the relationship between Section 4 and Section 5(a), which contains the Commission's authority, on its own motion or on complaint, to find any rate unlawful and to determine a just and reasonable rate to be placed into effect prospectively.

Although the Court's analysis of the statutory scheme of the NGA was done in depth, the actual holding in the case was limited. Mobile Gas Service Corporation, a distributor of natural gas, had a long term contract with United Gas Pipe Line Company to purchase gas for resale to a specific industrial customer, Ideal Cement Company, which in turn had a similar supply contract to buy the gas from Mobile. The Mobile-United contract was filed with the Commission and became part of the United's filed schedules of rates and contracts. *Mobile, supra* at 335, 336. Thereafter, United, without the consent of Mobile, filed with the Commission new rate schedules purporting to increase the rate on gas for resale to Ideal. Before the

Court was whether United might, without the consent of Mobile, change the rates specified in its contract with Mobile simply by filing a new rate schedule with the Commission. The Court held that the NGA does not give natural gas companies the right to change their rate contracts by their own unilateral action. *Id.* at 337, 347.

Moreover, in its overall discussion of the NGA, the Court in *Mobile* noted that Sections 4 and 5 are parts of a single statutory scheme under which rates are established initially by the natural gas companies, by contract or otherwise, and under which all rates are subject to be modified by the Commission upon a finding that they are unlawful. The Court pointed out that the NGA merely defines the review powers of the Commission and imposes such duties on the natural gas companies as is necessary to effectuate those powers but it does not grant or define the initial rate setting powers of natural gas companies. The Court stated that the powers of the Commission are defined by Sections 4 and 5 of the NGA. In this regard, the basic power of the Commission is given by Section 5(a) to set aside and modify any rate or contract which it determines after hearing to be unjust, unreasonable, unduly discriminatory or preferential. The Court further mentioned that Section 5(a) applies to all rates of a natural gas company, whether long-established or newly changed, although in the case of the newly changed rate, the power of the Commission to review is further implemented by the Section 4 suspension and refund procedures. *Id.* at 341.

Sierra, similar to *Mobile*, involved a contract between an electric utility and a distributor, which was on file with the Commission and subject to its jurisdiction. In *Sierra*, the utility also attempted to change the contract unilaterally, by filing for a rate increase under Section 205(d) of the Federal Power Act (FPA), 16 U.S.C. § 824(d). *Sierra*, *supra* at 351, 352.

The Court noted that Sections 205(c), (d), and (e) and 206(a) of the FPA are substantially identical to Sections 4(b), (b) and (e), and 5(a), respectively, of the NGA, *id.* at 350, 351. It then held that is ruling in *Mobile* that th- NGA does not authorize unilateral contract changes is an interpretation that is equally applicable to the FPA. The Court, therefore, concluded that neither the filing of the new rate nor the Commission finding that it was not unlawful was effective to change the utility-distributor contract. *Id.* at 353.

Moreover, the Court in *Sierra* reached a question not present in the *Mobile* case. The Court noted that the Commission has power under Section 206(a) of the FPA to prescribe a change in contract rates if it determines such rates to be unlawful. In *Sierra,* the Court overturned the Commission action not because the Commission did not have power to change the contract involved but because the Commission had not made the necessary finding that the contract rate in question was "unjust, unreasonable, unduly discriminatory or preferential", as required in Section 206(a) of the FPA.

In light of the above *Mobile-Sierra* discussion, two points become clear. First, in the present case the specific ruling in *Sierra* proscribing unilateral contract changes by rate filings, is not applicable. MSS is not attempting, by filing the 1982 System Agreement, to change unilaterally any existing contract it has with the parties in this cause. Rather, the 1982 System Agreement itself is an agreed-upon contract, which is a rate change from the former rates that were approved in the 1973 System Agreement. What the intervening parties are attempting to do is to persuade the Commission to exercise its powers under Sections 205 and 206 of the FPA, to revise that contract on the basis that it is unjust, unreasonable, unduly discriminatory or preferential. The second point made clear by *Mobile-Sierra* is that the Commission has the power, pursuant to Sections 205 and 206 of the FPA, to make such

a revision and that it may set new rates by altering the 1982 System Agreement. Moreover, since this cause arises under both Section 205 and Section 206 (see Ordering Paragraph (C) of the Commission's July 29, 1982 order setting the hearing herein), and since this proceeding involves a rate change, not a newly filed rate, the refund provisions of Section 205(e) of the FPA are applicable.

Further, *Borough of Lansdale, Pa. v. F.P.C., supra,* and *Permian Basin Area Rate Cases, supra,* do not make the *Mobile-Sierra* doctrine applicable to the present case. *Borough of Lansdale* merely indicates that the *Mobile-Sierra* doctrine is applicable even when the underlying contract has not been filed with the Commission. *Permian Basin* merely restated in different language the principle in *Mobile* that contracts should not be abrogated unless it is shown to be in the public interest to do so, a finding necessarily required to be made by the Commission to revise a contract rate pursuant to Sections 205 and 206 of the FPA.

In light of the above evaluation, the *Mobile-Sierra* doctrine does not present any bar to the adoption of any of the proposals set forth in this proceeding for governing the transactions among the MSU operating companies. *Mobile-Sierra* does highlight the authority of the Commission to approve the 1982 System Agreement as filed, or to revise it if to do so is in the public interest. As the Supreme Court noted in *Mobile, supra* at 344, "contracts remain fully subject to the paramount power of the Commission to modify them when necessary in the public interest."

2. Burden of Proof

APSC further asserts that the 1982 System Agreement is a rate change, not a rate increase, and that, therefore, the parties opposing the 1982 System Agreement have the burden of showing it to be unjust, unreasonable, discriminatory or preferential. The necessary implication of this argument is that the proponents of the adoption of the

1982 System Agreement need not demonstrate that it is just, reasonable, non-discriminatory and non-preferential. Moreover, APSC suggests that, if the 1982 System Agreement is rejected, the Commission must consider reinstating the 1973 System Agreement and may only adopt an alternative to the 1973 System Agreement if it finds that agreement to be unjust, unreasonable and unduly discriminatory. Further, APSC argues that any alternative adopted (i.e., an equalization proposal) must be shown by its proponents to be just, reasonable, non-discriminatory and non-preferential.

The above argument that the 1982 System Agreement is not a rate increase within the meaning of Section 205(e) of the FPA, thereby shifting the burden of proof, is unpersuasive. Section 205 does not apply only to rate increases but to any change in the filed rate. In addition, *Public Service commission of the State of New York v. F.E.R.C.*, 642 F.2d 1335, 1345 (D.C. Cir. 1980) relied upon by APSC, is not in point. That case, dealing with the sister provision to Section 205 in the NGA, Section 4, does not hold that only rate increases are covered there under. Rather, the Court ruled that if a portion of the rate is not changed by the proposed revisions to the rate, such portion of the rate does not have to be established as just and reasonable. Also, it was noted that anyone wishing to challenge the unrevised portion of the rate must do so through Section 5(a) procedures and would have the burden for showing that the unchanged portion is unjust, unreasonable, unduly discriminatory or preferential. *Id.* at 1345. Since the 1982 System Agreement does constitute a change to the rates in the 1973 Agreement, it is a filing under Section 205 and the applicant, MSS, has the burden of proof to show that it is just and reasonable.

Further, even assuming *arguendo* the validity of APSC's position, it must be concluded that the formula rates in the 1982 System Agreement will result in a rate increase for at least some of the MSU operating companies. Some

operating companies will pay more and some less under the 1982 System Agreement than under the 1973 System Agreement, and the rates will increase or decrease depending on how short or long the operating companies are. Certainly, once the new nuclear plants come on line, the rates under the 1982 System Agreement will increase for some companies since this will substantially affect the short and long relationships. Therefore, the 1982 System Agreement is a rate increase within the meaning of Section 205(e) and the burden of proof is on MSS to show that it is just and reasonable.

APSC is partially correct, however, in its burden of proof argument. While MSS had the burden of proof with regard to the 1982 System Agreement since it is a rate change under Section 205 of the FPA, the parties who seek a revised agreement under the Commission's powers in Section 206(a), must establish that the revised proposal, be it that of LPSC, the Staff, CNO or MPSC, is just, reasonable and not unduly discriminatory or preferential. Moreover, as the 1982 System Agreement has been accepted for filing and is now in effect pursuant to the Commission's July 29, 1982 order setting this cause for hearing, the 1973 System Agreement has been superseded and can only be reinstated if it is found to be just and reasonable.

In any event, the burden of proof argument is largely academic. A very full record was developed herein and findings can be made to reject or support any of the five basic proposals (MSS, LPSC, the Staff, CNO, MPSC), depending upon the decisionmaker's assessment of the extensive evidence presented in this cause. Nor are the Presiding Judge and the Commission limited to approving one of the proposals advanced by the parties. Rather, under Section 206(a) of the FPA, the 1982 System Agreement can be revised in any fashion justified by the evidence of record so that just and reasonable rates will result from that Agreement. And, because the 1982 System Agree-

ment is a rate increase under Section 205 of the FPA, refunds may be ordered, if appropriate, from the date the 1982 System Agreement went into effect.

3. State-Federal Jurisdiction Conflict

The parties favoring adoption of the 1982 System Agreement as filed make a strong argument that none of the equalization proposals should be adopted because of their impact on the State-Federal jurisdictional relationship. This argument has two aspects. First, the contention is that ordering of cost equalization in this cause would constitute an impermissable extention of Federal regulation into matters reserved to the State under the FPA. Specifically, it is asserted that Sections 201(a) and (b) of the FPA, 16 U.S.C. §§824(a) and (b), prohibit cost equalization since it would extend Federal jurisdiction over generating plants, which are not intended to be jurisdictional facilities under the FPA. The reasoning is that cost equalization, by changing the operating companies' responsibilities for production facilities, would have such an impact on rate base in the State jurisdictions involved that it would in effect constitute regulation of the generating facilities, an area that is reserved to the States under Sections 201(a) and (b) of the FPA. In this regard, it is pointed out that, were the Commission to adopt the Staff equalization methodology, the impact would be to remove from the State commissions control of the vast majority of the cost of rendering service within each jurisdiction (APSC Ex. 2, pp. 46, 47). For example, if the Staff proposal was approved, more than 75% of rate base would be subject to FERC jurisdiction and an even greater percentage of the operation and maintenance expenses would be subject to FERC jurisdiction, because of the significant impact of fuel costs included in the production function. The contention is that, if the State commissions were to accept the Staff plan, they would have very little remaining control over the absolute level of rates that the retail customers within their jurisdiction would be required to pay. (*Id.*)

The second aspect of the argument is that, even if the Commission possesses jurisdiction to approve a form of production cost equalization because of its control over the Middle South power pool, public policy militates against the exercise of such authority. In this regard, it suggested that sound policy calls for regulating generating plant and retail rates locally, rather than having them preempted by Federal regulation. And, it is asserted that the policy in the FPA to maintain competition to the maximum extent possible, operates in favor of rejection of the cost equalization proposals.

The proponents of the 1982 System Agreement cite *Pacific Gas and Electric Co. v. State Energy Resources Conservation and Development Commission,* 461 U.S. 190, 205 (1983), for the proposition that Congress intended the states to retain their traditional responsibility for regulating utilities. Also, they rely on *Connecticut Light and Power Company v. F.P.C.,* 324 U.S. 515, 522-23, 527-29 (1945), where the Court noted that the Commission should not have jurisdiction under the FPA over facilities used for the generation of electricity, and then rejected a broader view of Federal control espoused by the second Circuit in *Hartfort electric Light Co. v. F.P.C.,* 131 F.2d 953 (2d cir. 1942), *cert. denied* 319 U.S. 741 (1943). Moreover, it is pointed out that it is well settled that the Commission has no authority to establish retail rates, *Cities of Batavia, et al. v. F.E.R.C.,* 672 F.2d 64, 68, n. 2 (D.C. Cir. 1978), although the Commission may consider the impact of its determination on retail rates in certain circumstances, such as cases involving price squeeze, *F.P.C. v. Conway, Corp.* 426 U.S. 271 (1976).

In addition, the opponents of equalization emphasize the legislative history of the FPA. They assert that the FPA was a direct result of the Supreme Court decision in *Public Utilities Commission v. Attleboro Steam & Electric Company,* 273 U.S. 83 (1927), which struck down the right of the state to fix the rates for wholesale power transactions

in interstate commerce. In *Attleboro,* where the so-called "bright line" distinction between State and Federal jurisdiction was established, the court validated the State's power to regulate rates charged to local customers, but created a gap in the scheme of regulation over electric utilities by barring regulation of wholesale power transactions in interstate commerce. This gap the Congress moved to fill in 1935 by passing the FPA, *New England Power Company v. New Hampshire,* 455 U.S. 331, 340 (1982); *Duke Power Co. v. F.P.C.,* 401 F.2d 930, 934 (D.C. Cir. 1968). It is noted that the legislative history of the FPA reflects that it was conceived entirely as a supplement to, and not as a substitute for State, regulation, Hearings on HR. 5432 before the House Committee on Interstate and Foreign Commerce, 74th Congress, 1st Sess., p. 384 (1935). Also, the suggestion to include all generation facilities under the comprehensive jurisdiction of the Commission came under close scrutiny during the 1935 hearings, Hearings on S. 1725 before the Senate Committee on Interstate Commerce, 74th Congress, 1st Sess. pp. 347-48 (1935), but was deleted by the House, HR. Report No. 1318, 74th Congress, 1st Sess. p. 2627 (1935). Therefore, the final version of the FPA containing the present, language leaves no doubt that Congress did not intend for the Commission to have jurisdiction over generating facilities.

A further complication raised by the State-Federal jurisdiction conflict is the fact that the State commissions would be bound to accept the rulings of this Commission in their local ratemaking proceedings. Despite the dicta in *Georgia Power Company,* 52 FPC 1343, 1349 (1974) that the state commission would be at liberty in setting retail rates to disregard the decision of this Commission, later authority indicates that, once this Commission allows a utility to charge a rate reflecting investment in a particular plant, the State commission with regulatory authority over the utility is required by the Supremacy Clause of the

United States constitution to allow the utility to recover the cost of the FERC approved rate in its retail rates, *Washington Gas Light Company, v. Public Service Commission,* 452 A. 2d 375, 385-86 (D.C. App. 1982), *cert. denied,* 103 S. Ct. 2454 (1983); *Eastern Edison Co. v. The Department of Public Utilities,* 388 Mass. 292, 446 N.E. 2d 684, 690 (1983); *Northern State Power Co. v. Hagan,* 314 N.W. 2d 32, 38 (N.D. 1981); *Narragansett Electric Co. v. Burke,* 119, R.I. 559, 564-65, 568, 381 A.2d 1358, 1361, 1363 (1977), *cert. denied,* 435 U.S. 972 (1978) (hereinafter referred to as the "*Narragansett* doctrine"). Under the *Narragansett* doctrine, should this Commission order that production costs be equalized as a result of a revision of the 1982 System Agreement, which is subject to Federal jurisdiction, the State commissions would be compelled to reflect that ruling in their retail rates. As a result, State commissions will not be at liberty to ignore the FERC ruling and exclude portions of the equalized production plant from rate base. Accordingly, State commissions might be reluctant to certify generating facilities under such circumstances.

To resolve the two basic jurisdictional issues presented, it is helpful to set out the pertinent provisions of the FPA. Sections 201(a) and (b) 16 U.S.C. §§824(a) and (b), read as follows.

(a) It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in the subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the State.

(b) The provisions of this subchapter shall apply to the transmission of electrical energy in interstate commerce and to the sale of electrical energy at wholesale in interstate commerce, but shall not apply to any other sale of electrical energy or deprive a State or State Commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electrical energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electrical energy or over facilities used in local distribution or only for the transmission of electrical energy in intrastate commerce, or over facilities for the transmission of the electrical energy consumed wholly by the transmitter.

As can be seen, the language of the statute indicates that this Commission has jurisdiction only of matters which are not subject to the regulation by the States, and that it does not have jurisdiction over generating facilities. However, the statute specifically gives the Commission authority over the sale of electrical energy at wholesale in interstate commerce. As a result, there is no doubt that the Commission does have jurisdiction over the 1982 System Agreement in that it constitutes the sale of electrical energy at wholesale in interstate commerce between the operating companies of the Middle South system.

In addition, the pertinent provisions of the FPA implementing the Commission's basic jurisdiction must be considered. These are Sections 205 (c), (d) and (e), 16 U.S.C. §§824d(c), (d) and (e), under which the jurisdictional utility can make a change in an existing rate, and Section 206(a), 16 U.S.C., §824e(a), under which the Commission has the power to set rates to be charged by the jurisdictional utility. Since the 1982 System Agreement does constitute a rate change filed under Section 205, the jurisdiction of the Commission under Section 206(a) to revise the Agreement

and set different rates (as, for example, by ordering some form of production cost equalization) cannot reasonably be challenged.

In a recent decision, *Arkansas electric Corp. v. Arkansas Public Service Commission,* 461 U.S. 375, 390 (1983), the Supreme Court rejected the "wholesale/retail" bright line distinction in *Attleboro,* when the Court indicated that modern jurisprudence has usually, although not always, given more latitude to State regulation than the more categorical approach, of which *Attleboro* is an example. Therefore, the Court did broaden the area of state regulation by upholding jurisdiction of the APSC over a rural electric cooperative, but it also noted that the general trend in the modern commerce Clause juris prudence is to look to the nature of the State regulation involved, the objective of the State and the effect of the regulation upon the national interest in commerce, to resolve the jurisdictional issue. Further, the Court recognized that there are an infinite variety of cases in which the regulation of local matters may also operate as a regulation of interstate commerce, and that reconciliation of the State and national power should be obtained by some appraisal and accommodation of the competing demands of the State and national interests involved. *Id.*

In this regard, the instant case presents a situation where reconciliation of overlapping State and Federal jurisdiction must be obtained. The State commissions clearly have control over the generating plants that they have approved for construction, while this Commission has jurisdiction over the interstate transactions among the MSU operating companies made pursuant to the 1982 System Agreement. While due deference has to be given to the State jurisdiction over generating facilities, it must nonetheless be recognized that this Commission has the authority, in exercising its public interest duties under Sections 205 and 206 of the FPA, to assure that the intercompany transactions are just, reasonable, non-discrimi-

natory and non-preferential. Moreover, this Commission has a broader perspective, since its jurisdiction pervades all of the States involved. Therefore, the Commission is perhaps in the best position to reach the most equitable result and to act in the public interest, rather than to be controlled by the necessarily parochial concerns of the States.

In any event, the language in Section 201(a) of the FPA restricting FERC's authority to matters not subject to State regulation, does not nullify the clear authority of the Commission to regulate the 1982 System Agreement, even if the exercise of FERC jurisdiction might be inconsistent with the broadly expressed statement in Section 201(a). *See F.P.C. v. Southern California Edison Co.*, 376 U.S. 205, 215 (1964); *Connecticut Light & Power Co. v. F.P.C., supra* at 527. The restrictive language in Section 201(a) is not a limitation on the use by the Commission of authority specifically conferred on it by Congress, *Duke Power Co. v. F.P.C.*, 401 F.2d 930, 938 (D.C. Cir. 1968), in this instance, the power of the Commission to regulate wholesale sales in interstate commerce in the form of MSS power pool transactions. The fact that State commissions also have regulatory power in an affected area, rate base, does not preclude exercise of the Commission's authority, *Connecticut Light & Power Co. v. F.P.C., supra* at 524-25.

Nonetheless, while this Commission does have the power, from a jurisdictional standpoint, to order production cost equalization, this power must be exercised with caution since it will result in a substantial impact on the retail ratemaking ability of the State commissions involved. The legislative history of the FPA and the case law show that Federal regulations is meant to be supplemental to, not in place of, State regulation. Therefore, exercise by FERC of its overlapping jurisdiction in this cause must be tempered and weighed against the policy consideration that generation facilities and retail rate regulation should be

left to the State commissions. Since, under the *Narragansett* line of cases discussed *supra*, State regulation must conform to Federal regulation, the intrusion of Federal jurisdiction into State ratemaking must be done only after a careful balancing of the State and Federal interests involved. According, in resolving the current case, the deference due to State regulation is a very important factor that will be considered as weighing against imposition of any equalization proposal. As a result, equalization will only be ordered if there are substantial reasons making equalization necessary to ensure a just and reasonable, non-discriminatory agreement governing transaction among the operating companies of the Middle South system.

In light of the above discussion, it must be concluded that production cost equalization can be ordered as properly within the jurisdiction of this Commission, if there are sufficient public interest reasons for revising the 1982 System Agreement in this fashion. However, the statutory scheme of the FPA and the deference that should be paid to the state jurisdictional ratemaking authority is an important factor to be considered as weighing against the imposition of equalization.

4. Other Alleged Impediment to Equalization

a. Impact on Power Pooling

Certain parties opposing equalization (AP&L Initial Br., pp. 106-07; APSC Initial Br. pp. 70-72; Ark. Ind. Initial Br. pp. 35-40; Ark-Mo Cong. Del. Initial Br., pp. 28 and 29; Conway Initial Br., pp. 37-39) argue that equalization should not be adopted because of the deleterious effect it would have on power pooling in the United States. It is suggested that the ordering of equalization would violate Section 202(a) of the FPA, 16 U.S.C. §824(a), and Section 205(b) of the Public Utility Regulatory Policy Act (PURPA), 16 U.S.C. §824a-1(b) (Supp. V 1981). In this regard, it is asserted that ordering equalization amounts to regulatory coercion, whereas both the FPA and PURPA provide, in

the section cited, for encouragement of utility transactions on a voluntary basis. Also, it is pointed out that the Supreme Court has indicated that the thrust in Section 202(a) of the FPA is to encourage voluntary interconnection of utilities, *Otter Tail Power Co. v. United States*, 410 U.S. 366, 373 (1973). Moreover, it is suggested that Section 205(b) of PURPA continues the voluntary coordination rationale of Section 202(a) of the FPA and directs FERC to encourage negotiations for pooling arrangements (Power Pooling in the United States (1981), Item by Ref. B, p. 1.)

Further, the parties opposing equalization argue that it would create difficulties for other pools similar to the Middle South system, whether they are made up of affiliated or nonaffiliated members, since they also may be subject to the imposition of production cost equalization. Therefore, it is suggested that ordering of equalization would provide a disincentive to voluntary pooling. The opposing parties contend that equalization could contravene the purpose of a power pool to achieve economies for its members that could not be achieved operating independently and that this would have a "chilling" effect on the willingness of companies to participate in power pool arrangements, because of the danger of having the fruits of past economic and operating decisions taken away from them at any time (APSC Ex. 2, pp. 48, 49). In addition, it is averred that utilities with low operating costs would be impeded from joining a power pool, since their low costs might end up being equalized and the result might be higher overall costs for their customers.

The proponents of equalization, in rebuttal, argue that this case involves operating companies under common ownership in a pooling arrangement on a system that is planned, constructed and operated as a single utility. Therefore, it is asserted that a decision ordering equalization will not have a precedential effect on pools involving nonaffiliated companies, nor will it discourage power pool-

ing otherwise, since it will be limited to the facts in this proceeding. In addition, the argument is made that, even with regard to cost allocation among affiliated companies, Section 206(a) of the FPA provides that the Commission cannot order into effect contract terms of its own determination, such as production cost equalization, unless it first finds that the proposed contract rate is unjust, unreasonable or unduly discriminatory. It is noted that the Commission, in *Georgia Power Company*, 52 FPC 1343, 1348 (1974), held that the proposal of the Southern operating companies was just and reasonable under the circumstances in that case and declined to order cost equalization. It is suggested that the Commission's discussion in *Georgia Power* indicates that cost equalization is a matter for decision on a case-by-case basis and that, therefore, the ordering of equalization in this cause will be limited to the circumstances presented herein.

On analysis, the arguments of the proponents of production cost equalization are better taken on the power pooling issue. Any ordering of equalization in this cause must necessarily be restricted to the factual circumstances justifying such an order and, therefore, it is unlikely that a utility in another pool would forego the economies of scale and enhanced reliability benefits of pooling because of any decision herein. Nor would a utility be likely to refrain from entering into a power pool, with its positive benefits, because of the speculation that production cost equalization might in the future be imposed upon it. Further, regarding non-affiliated pools, since these are clearly voluntary arrangements, a utility could ensure its ability to withdraw from the pool if production cost equalization might be imposed by seeking appropriate contract protection in the pooling agreement.

Further, the policy to encourage voluntary pooling contained in FPA and PURPA cannot operate to block the Commission power under Section 206(a) of the FPA to reallocate cost and order expansion of the scope of power

pooling transactions, if to do so is necessary in the public interest. *See Central Iowa Power Cooperative, et al. v. F.E.R.C.*, 606 F.2d 1156 (D.C. Cir. 1979) and *Municipalities of Groton v. F.E.R.C.*, 587 F.2d 1296 (D.C. Cir. 1978). Accordingly, if the Commission determines that it is in the public interest to reform the 1982 System Agreement to order production cost equalization as a method of providing just and reasonable rates for the Middle South system transactions, the suggestion that there is some potential, speculative adverse impact on the power pooling in the United States cannot operate to impede the Commission from fulfilling its statutory responsibilities under Section 206(a) of the FPA.

b. Public Utility Holding Company Act

A further argument lodged by APSC and Benton, (APSC Initial Br., pp. 72-75; Benton, Initial Br., pp. 19-26) is that this Commission is not the appropriate regulatory agency to consider the corporate interrelationships within the Middle South system and that any rate treatment based on such consideration would violate the primary authority of SEC over regulated public utility holding companies under the provisions of the Public Utility Holding Company Act (PUHCA), 15 U.S.C. §§79, *et seq.*

It is asserted that to ignore the separate legal existence of AP&L and to transform MSU, a holding company, into a single monolithic operating utility would be to ignore the control authority and basic arms of the PUHCA. The contention is made that a principal purpose of the PUHCA is to prevent the manipulation of an operating utility owned by a holding company to the detriment of the customers of the operating utility. In this regard, the language in Section 1 of the PUHCA indicates that the public interest may be adversely affected by dealings where the subsidiary company is charged excessively for services, construction work, materials or equipment, or enters into transactions in the absence of arms-length bargaining; or where control

of accounting and rate policies of the subsidiary is such as to complicate obstruct State regulation, 15 U.S.C. §79a(b). The gravemen of the argument is that the PUHCA is designed (1) to prevent holding companies from operating as monolithic utilities beyond the effective control of State regulatory agencies beyond the effective control of State regulatory agencies, and (2) to recognize the separate existence of subsidiary utilities so that each will be operated in the interest of its ratepayers and subject to the regulation by the State. To obtain these objectives, SEC has extensive authority under Section 13 of the PUHCA, 15 U.S.C. §79m, to oversee contracts between and among holding companies and their operating utilities and other subsidiaries. As a result, the parties opposing equalization assert that, for FERC to hold that the separate identity of AP&L may be ignored and that MSU can be treated as a single utility for the purpose of allocating production costs to AP&L without its consent and without approval by the State regulatory agency involved, would be to reinstate one of the problems that PUHCA was intended to eliminate.

Further, it is pointed out that the PUHCA is designed to regulate integrated public utility systems, as defined in 15 U.S.C. §79BB(a)(29), and that SEC has the authority to examine and control the intercorporate structure of electric utilities and their operating subsidiaries, 15 U.S.C. §79K(a). The argument is advanced that the purpose of the PUHCA was to change national holding companies into simplified, regional systems, as shown in the legislative history of the PUHCA, Senate Report 621 and House Report 1092, 74th Cong. 1st Sess. (1935).

Also, while the amount of control exercised by a holding company over its subsidiaries is relevant to determining, for SEC purposes, whether the company is an integrated utility system under the PUHCA and while MSU and its operating companies are considered by SEC to be an integrated public utility system, the parties opposing equal-

ization contend that these legal conclusions under the PUHCA are not relevant for FERC ratemaking purposes. It is asserted that the fact that Middle South is recognized as an integrated public utility system under the PUHCA for SEC regulatory purposes, is not a basis for the regional ratemaking that would be reflected by adoption of production cost equalization in this cause. As a result, it is suggested that the FPA does not give FERC jurisdiction to address questions of whether a system is a single integrated public utility system in exercising its responsibilities to establish interstate wholesale rates and to regulate power pools. FERC authority is allegedly limited to consideration of rate cases and approval of contracts among utilities which deal in interstate commerce. The parties opposing equalization take the position that to use SEC precedent and rulings on MSU under the PUHCA to eliminate State regulation over most of the business of the MSU operating companies, is contrary to the FPA and the PUHCA, and erodes the PUHCA's purpose of protecting State jurisdiction.

On the other hand, the parties favoring equalization point out that the PUHCA was designed to provide a more effective regulation of public utilities and did not return regulatory authority solely to the States. In fact, it is noted that decisions by SEC override conflicting State statutory or State regulatory decisions, *Common Stock Holders Committee of Long Island Lighting v. SEC,* 18 F.2d 45 (2nd Cir. 1950), *cert denied* 340 U.S. 834 (1950); *Okin v. SEC,* 161 F.2d 978 (2nd Cir. 1947); *In re Standard Gas and Electric Co.,* 301 F.Supp. 1382 (D. Del. 1969), aff'd 433 F.2d 139; *In re Kings County Lighting Co.,* 72 F.Supp. 767 (E.D.N.Y. 1949).

In addition, it is suggested that, while the policy of the PUHCA was to limit large holding companies, this policy was to be carried out by the simplification of public utility holding company systems in such a manner as to keep together coordinated and integrated systems, 15 U.S.C.

§879a(c). The proponents of equalization further note that the SEC in its decision forming MSU stated that voluntary cooperation to achieve benefits for each of the several separate subsidiaries, as through power interchange contracts, is very different from the the operation of properties as a single system, *Electric Power and Light Corporation*, 29 SEC 52 (1949), *aff'd* 176 F.2d 687 (2d Cir. 1949). In that case, the SEC held that the operation of properties as a single system is what constitutes integration within the meaning of the PUHCA and such integrated operation assumes that separate corporate entities might be called on to sacrifice their particular interests for the overall good, *id.* at 65. As a result, it is argued that production cost equalization would be fully consistent with the prior SEC decisions concerning the Middle South system under the PUHCA.

Overall, the argument that the PUHCA constitutes a bar to ordering production cost allocation must be rejected. Whether MSU is considered to be an integrated public utility system within the meaning of the PUHCA is a matter properly determined by the SEC. And, if ordering equalization of production costs is necessary for this Commission to fulfull its public interest duties under Sections 205 and 206 of the FPA to prevent undue discrimination, preference or rate inequity for the customers of the operating utilities of the Middle South system, then this Commission is under an obligation to order such a result. These determinations are not mutually exclusive, giving one agency primary jurisdiction over integrated electric power systems. Rather, the FPA and the PUHCA are complementary, *Louisiana Power and Light Co.*, 13 FERC ¶61,220, at p. 61,507 (1980), and both statues give due deference to State authority as can be seen by the discussion in this Section and in Section VI D 3, *supra*. The PUHCA was not intended to confer exclusive jurisdiction on SEC over contracts between holding companies and their subsidiaries or between subsidiaries of holding com-

panies, although there is authority under the PUHCA for SEC to scrutinize such contracts. Therefore, a contract between subsidiaries of a holding company covering rates for wholesale sales of electricity in interstate commerce can come under the jurisdiction of FERC, even though it might concurrently come under the jurisdiction of SEC for other purposes. The concurrent SEC jurisdiction over such contracts involving the Middle South system and SEC rulings on MSU under the PUHCA, do not, therefore, present any bar to FERC's exercise of its power under the FPA to revise the 1982 System Agreement (as, for example, by ordering equalization), if to do so is in the public interest.

c. Miscellaneous

Certain other arguments against production cost equalization merit brief comment: (1) that equalization constitutes a forced purchase of capacity; (2) that equalization will make the State commissions reluctant to certify plants in their areas if the power is to be used elsewhere; and (3) that equalization will result in an anticompetitive price squeeze situation.

None of the above contentions is persuasive. First, no sale would actually occur under any of the equalization proposals and, in fact, the individual operating company's responsibility for the various plants will vary from time to time depending on the allocation methodology employed by the equalization proposal.

Also, while it is correct that FERC cannot compel one utility to purchase from or sell to another, *Southern Company Services, Inc.*, 20 FERC ¶61,332 (1982), this situation is not present in the instant case. The MSU operating companies have not refused to share generating costs but rather the 1982 System Agreement covers how such exchanges should take place and at what rates. The Commission in this proceeding is not dealing with a forced purchase but with the proper method of allocating costs

among the affiliated MSU companies, a matter well within FERC's authority. *See Central Iowa Power Cooperative v. F.E.R.C,* 606 F.2d 1156 (D.C. Cir. 1979) and *Municipalities of Groton v. F.E.R.C.,* 587 F.2d 1296 (D.C. Cir. 1978).

Furthermore, ordering of equalization represents no real obstacle to State plant certification since the State commissions have often dealt with plants having multi-state uses, such as Grand Gulf in Mississippi and the recent Independence Unit in Arkansas, part of whose capacity is being sold to MP&L. The benefits of economics of scale and rehability inherent in multi-state pooling arrangements will almost certainly out weight the reluctance of a Sate commission to certify a plant because a portion of its power is to be used elsewhere, particularly when the State commission is aware that its ratepayers will correspondingly share in economy and reliability benefits from Middle South plants in other jurisdictions.

In addition, the concern that production cost equalization might lead to a price squeeze for AP&L's wholesale customers, a situation prohibited by *F.P.C. v. Conway Corp.,* 426 U.S. 271 (1976), is misplaced. The only basis for this complaint is that APSC would ignore this Commission's ordering of cost equalization in setting retail rates and base those rates on AP&L individual costs. For APSC to do so, it would have to ignore the *Narragansett* doctrine discussed *supra,* under which a State commission (in this case APSC) is bound to allow the utility to recover the cost of FERC approved rates in the utility's retail rates. Therefore, the wholesale customers would have an appropriate legal vehicle to rectify the situation if it should occur. As a result, this anticompetitive concern is not of sufficient substance to create any valid impediment to the ordering of cost equalization, if the circumstances of the present case so warrant.

E. Economic Impacts of the Production Cost Allocation Proposals

In assessing the economic impacts of implementation of the various production cost allocation proposals, three distinct areas can be considered; (1) the impact on revenue requirements of the MSU operating companies; (2) the impact on the projected average annual costs of electricity; and (3) specific impacts in the various jurisdictions. These areas will be considered seriatim.

1. Impacts on Revenue Requirements

The impacts on the revenue requirements of the MSU operating companies was presented in four exhibits prepared by MSS that used the revenue requirements of the 1973 System Agreement as the basis for comparison. These exhibits show the revenue requirement change for each of the four operating companies based on a shift from the 1973 System Agreement to: the 1982 System Agreement (MSS Ex. 19); the Staff proposal (MSS Ex. 20); the LPSC proposal (MSS Ex. 21), and the MSPC proposal (MSS Ex. 23). These exhibits reflect comparisons of intercompany capacity and energy sales for the ten year period from January 1, 1984 to December 31, 1993, and use data taken from Middle South's current ten year load and capability forecast. Some of the principal parameters reflected in the comparisons are the load forecast fuel price forecast, economic dispatch forecast, generating unit characteristics, the capacity addition schedule, and rate of return on common equity. Also reflected in the exhibits are the allocation of revenue requirements necessary to cover MSE's costs of generating power and energy from Grand Gulf Units 1 and 2. All the parameters were held constant in the studies done to prepare the exhibits, to achieve a comparison of the effects of the different allocation methods. (MSS Ex. 17, pp. 31, 32, 71.) The format of the revenue requirements exhibits is that they are all four page documents, made up of one page schedules summarizing the

results for each operating company over the ten year period (MSS Ex. 17, p. 32). No exhibit was prepared by MSS for the CNO equalization proposal, probably because CNO had not settled upon a favored position at the time MSS prepared its rebuttal testimony. However, it is reasonable to conclude that the impact of CNO's equalization methodology would be substantially the same as the Staff's and LPSC's, because of the similarity of the CNO proposal to the Staff and LPSC proposals.

The revenue requirement ramifications of the various proposals over the ten year period can be summarized as follows: under the 1982 System Agreement, AP&L's revenue requirements would increase $29,050,000; LP&L's would increase $20,032,000; MP&L's would increase $9,017,000; and NOPSI's would decrease $55,267,000. Under the Staff proposal, AP&L's revenue requirements would decrease $3,534,998,000; LP&L's would decrease $2,528,555,000; MP&L's would decrease $997,769,000 and NOPSI's would decrease $847,737,000. Under the LPSC proposal, AP&L's revenue requirements would increase $2,875, $985,000; LP&L's would decrease $420,038,000; MP&L's would decrease $1,153,784,000; and NOPSI's would decrease $1,299,273,000. Under the MPSC proposal, AP&L's revenue requirements would increase $301,261,000; LP&L's would increase $666,293,000; MP&L's would decrease $758,979,000; and NOPSI's would decrease $202,480,000. (MSS Exs. 19, 20, 21, and 23.)

From the above figures, it is readily apparent why the Arkansas interests oppose production cost equalization. Under the Staff's proposal, there would be an increase of $3.5 billion in AP&L's revenue requirements and under the LPSC proposal, an increase of $2.8 billion over the ten year period. On the other hand, LP&L would have to pay $20 million in increased revenue requirements under the 1982 System Agreement as opposed to having its revenue requirements decrease by $2.5 billion under the Staff proposal and decrease by $420 million under the LPSC

proposal. Similarly, NOPSI would only get an increase of \$55 million under the 1982 System Agreement, while it would secure an increase of \$847 million under the Staff proposal and an increase of almost \$1.3 billion under the LPSC proposal. Also, MP&L would do much better under the MPSC proposal since its revenue requirements would decreased by \$758 million, whereas they would increase by \$9 million under the 1982 System Agreement. MP&L would, however, be benefitted by either equalization proposal since its decreased revenue requirements under the Staff proposal would be \$997 million and under the LPSC proposal \$1.1 billion, as opposed to the decrease of \$758 billion under its own proposal.

These exhibits, therefore, highlight the large revenue requirements shifts that will be occasioned depending upon which production cost allocation methodology is adopted in this cause. The Arkansas interests correctly point out that adoption of the 1982 System Agreement will cause the least variation in revenue requirements from those that would have been experienced under the 1973 System Agreement, but this represents only one factor to be taken into account and is not the controlling element in settling upon what is a just and reasonable plan. Moreover, the 1973 System Agreement is merely the norm used for comparison, it is not the criterion against which the reasonableness of the proposals is to be evaluated. Rather, based on an assessment of the operation of the Middle South system and the other ramifications of adopting the various proposals in this cause, as discussed elsewhere in this decision, an appropriate determination can be made as to whether it is just and reasonable to order the adoption of an agreement that will result in one of the cost shifts reflected in MSS Exhibits 19, 20, 21 and 23. If such cost shift is warranted by the circumstances of the case, then the mere fact that large sums are involved over a ten year period cannot act as deterrent to the taking of appropriate

action by this Commission in fulfilling its statutory responsibilities.

2. The Projected Average Annual Costs of Electricity

Evidence was presented at hearing to show projections of the average annual costs of electricity in cents per kilowatt hour for the years 1984 through 1992. This information was provided for the following production cost allocation proposals: the 1982 System Agreement, the Staff proposal, the LPSC proposal, and the MPSC proposal. Again, data was not prepared for any CNO proposal. Again, data was not prepared for any CNO proposal, but because of the similarities in that proposal to Staff's and LPSC's, it can be considered that the figures for those two proposals would be representative of the CNO equalization proposal. The projected annual average costs for the aforementioned production cost allocation proposals are shown in the following charts:

1982 System Agreement
Projected Average Annual
Cost of Electricity
(Cents Per Kilowatt Hour)

Year	*AP&L*	*LP&L*	*MP&L*	*NOPSI***
1983	4.92	5.16	6.40	6.21
1984	6.00	6.27	7.56	7.95
1985	5.97	7.05	8.56	8.86
1986	6.37	7.85	9.57	10.69
1987	6.84	7.00	10.03	11.28
1988	7.26	7.45	10.56	11.73
1989	7.54	8.07	11.27	11.68
1990	8.55	9.81	13.21	13.52
1991	8.97	11.42	14.53	14.45
1992	9.73	12.35	13.74	14.66

(MSS Ex. 59.)

Staff Proposal
Projected Average Annual
Cost of Electricity
(Cents Per Kilowat Hour)

Year	*AP&L*	*LP&L*	*MP&L*	*NOPSI*
1984	7.35	6.11	7.78	8.04
1985	7.25	6.52	8.08	8.12
1986	7.86	6.96	8.57	9.09
1987	8.08	6.24	9.00	9.49
1988	8.93	6.70	8.11	9.90
1989	9.65	7.10	8.63	9.65
1990	10.50	8.41	11.12	10.26
1991	11.06	9.82	12.18	10.98
1992	11.86	10.72	12.81	12.81

(MSS Ex. 60.)

LPSC Proposal
Projected Average Annual
Cost of Electricity
(Cents Per Kilowatt Hour)

Year	*AP&L*	*LP&L*	*MP&L*	*NOPSI*
1984	6.97	7.48	7.34	7.00
1985	7.27	7.17	8.24	7.57
1986	8.07	7.03	9.12	8.92
1987	7.76	7.09	8.48	8.79
1988	8.41	7.26	8.69	8.78
1989	8.91	7.81	9.14	8.36
1990	10.00	9.64	10.47	9.29
1991	10.85	10.66	11.81	10.11
1992	11.14	11.99	11.84	11.82

(MSS Ex. 61.)

MPSC Proposal
Projected Average Annual
Cost of Electricity
(Cents Per Kilowatt Hour)

Year	*AP&L*	*LP&L*	*MP&L*	*NOPSI*
1984	5.98	7.80	6.81	9.63
1985	5.95	8.14	7.25	9.26
1986	6.49	8.35	8.09	10.11
1987	6.91	7.29	8.76	10.52
1988	7.37	7.50	9.23	10.61
1989	7.77	8.00	9.88	10.52
1990	8.99	9.67	11.34	11.65
1991	9.33	10.98	12.84	12.75
1992	9.92	11.97	13.33	14.21

(MSS Ex. 63)

It is also instructive to consider the average of the projected average annual costs of electricity for the nine year period used in the charts shown above. This can be calculated by proposal for each operating company and reflected in the following chart:

Nine Year Average
Projected Average Annual
Cost of Electricity
(Cents Per Kilowatt Hour)

	AP&L	*LP&L*	*MP&L*	*NOPSI*
1982 System Agreement	7.47	8.59	11.00	11.65
Staff Proposal ...	9.17	7.62	9.59	9.82
LPSC Proposal ..	8.82	7.61	9.46	8.96
MPSC	7.63	8.86	9.73	11.03

As can be seen, the 1982 System Agreement would afford AP&L over the nine year period a cost advantage of 1.12 cents per kWh over LP&L, 3.53 cents per kWh over MP&L and 4.18 cents per kWh over NOPSI. The two equalization proposals have more level results with

the greatest advantages being enjoyed by LP&L, which would have 2.20 cents per kWh advantage over NOPSI under the Staff proposal and a 1.85 cent per kWh advantage over MP&L under the LPSC proposal. This, of course, is to be expected since the Staff and LPSC plans would equalize production costs over the projected nine year period. As to the MPSC plan, AP&L has a 1.23 edge over LP&L, a 2.10 advantage over MP&L and a 3.40 advantage over NOPSI, but MP&L would be 1.27 cents per kWh better off as compared to the 1982 System Agreement.

AP&L attempted to show that the projected annual average cost differences are substantially less than the historic advantage LP&L engaged over AP&L in this area during the 1973-82 time frame. AP&L also asserted that adoption of equalization would perpetuate the historic cost advantage enjoyed by LP&L. (AP&L Initial Br., pp. 39-46.) AP&L, however, only compared itself to LP&L and ignored the historic and projected figures for MP&L and NOPSI. For example, historic data for the same ten year period drawn from the same exhibit used by AP&L, MSS Exhibit 28, confirms that LP&L did, on average, enjoy a .98 cent per kWh advantage over AP&L, but it also shows that, on average over the period AP&L had a .71 cent per kWh edge over MP&L and a .79 cent per kWh advantage over NOPSI.

Moreover, on the nine year average projections, while LP&L would have a 1.55 and 1.21 cent per kWh advantage over AP&L under the Staff and LPSC proposals, respectively, AP&L would enjoy a .42 cent per kWh advantage over MP&L and a .55 cent per kWh edge over NOPSI under the Staff plan, while having a .62 cent per kWh advantage over MP&L and a .14 cent per kWh advantage over NOPSI under the LPSC proposal. AP&L would, therefore, benefit more under equalization than two of its sister companies.

When the overall costs, both historic and projected, are taken into account, AP&L's cost disadvantage argument must be viewed as unpersuasive. The projected rate disparities under the 1982 System Agreement would give AP&L a greater advantage over LP&L than LP&L enjoyed historically over AP&L (1.15 versus .98) and would result in very substantial disparities of 3.53 cents per kWh for MP&L and 4.18 cents per kWh for NOPSI when compared to AP&L over the projected nine year period.

Again, as with the revenue requirements, these average annual costs of electricity are instructive in showing which proposal favors which jurisdiction. As shown on the above charts, AP&L would benefit from adoption of the 1982 System Agreement, while MP&L, LP&L and NOPSI would all benefit more by adoption of either the Staff or the LPSC proposal. In addition, LP&L and NOPSI would both do better under the Staff and LPSC proposals than under the MPSC proposal.

These figures on projected average annual costs of electricity also reveal that, while all the companies will sustain substantial increases over the period involved, AP&L receives a distinct benefit in average annual costs from adoption of the 1982 System Agreement. Again, as with revenue requirements, this alone does not control whether the 1982 System Agreement should be approved or rejected, but rather it is a factor to be taken into account when the overall determination is made as to which proposal constitutes a just and reasonable arrangement to govern the formula rates that will be reflected in the pooling agreement among the MSU operating companies.

It should be kept in mind in reviewing the average annual costs of electricity that these costs cannot be equated with rates that might be put into effect in the various jurisdictions, although they are an important factor in determining such rates. Also, it should be pointed out that a disparity in rates is not in and of itself indicative

of inequity. Cost of service is based on many factors that vary from jurisdiction to jurisdiction, and it is not one of the objectives of the Middle South power pooling agreement to achieve uniform rates across the system.

3. Specific Impacts in Various Jurisdictions

With regard to specific effects of the production cost allocation proposals, evidence was presented on the impact that the equalization proposals would have in Arkansas because of the increase in rates over the rates that would go into effect should the 1982 System Agreement be adopted. Conversely, there was evidence over the impact in Louisiana because of the increase in rates that would be occasioned there if the 1982 System Agreement were adopted as opposed to a form of production cost equalization.

Regarding the impact of equalization in Arkansas, the following situation was presented. Reynolds Metals Company, at the time of the hearing, operated two aluminum reduction plants in Arkansas and four other manufacturing facilities. In 1981, Reynolds represented about 25% of the energy sales of AP&L and, even under the recession in 1982, contributed approximately $49 million to AP&L's revenues. At full operation of its six plants, Reynolds purchases over $70 million of electrical power from AP&L. However, that figure has to be reduced to reflect the present curtailed operations of Reynolds in Arkansas, as well as the closure of a bauxite mine and much of Reynolds' alumina refining capacity, which action was scheduled for the end of 1983. (Ark. Ind. Ex. 2, p. 5, 6.)

The cost of electrical power is critical for Reynolds' aluminum reduction plants since its affects its ability to operate these plants competitively. Moreover, of Reynolds' total demand in Arkansas of about 400 MW, the two reduction plants account for approximately 385 MW. (Id. at 3, 4; Tr. 6780.) Since power represents a far greater portion of total production costs in a reduction plant than in

a typical non-aluminum manufacturing plant, the reduction plant is exceptionally sensitive to power costs, which are a determining factor in deciding the extent to which various reduction plants can operate during times of curtailment of aluminum production (Ark. Ind. Ex. 2, pp. 4-5).

Reynolds has dealt with AP&L for four decades and entered into a new eight year contract with AP&L in 1983. This new contract establishes rates using a formula under which AP&L's cost of producing and delivering power will be reflected in Reynolds rates. (Id. at 11.) As a result, any increased costs sustained by AP&L as a result of equalization will be felt by Reynolds and this has raised concerns over whether Reynolds' operations in Arkansas can be sustained at historical levels, particularly in view of the highly competitive nature of the business of producing aluminum (id. at 8, 10).

In addition, the potential effects of increased costs for AP&L on Riceland Foods was brought out. Riceland Foods is a farmer-owned cooperative with over 14,000 members. Riceland handles between 30 and 50% of the state's soybean crop and 45 to 60% of the rice crop. About 60 to 65% of its $636 million in 1982 sales went to the export market. (Ark. Ind. Ex. 3, pp. 2, 3.) The farmers in Arkansas will be affected by increases in electric costs in two ways: first, there will be higher irrigation, grain drying and storage costs on the farm itself; and second, there will be higher processing costs at Riceland's plants. Since the price of farm goods is determined by an open market of international scope, these cost increases are not easily passed along but would tend to reduce the farmer's profit margin. (Id. at 6, 7.) Riceland's plants have an aggregate demand of 47 MW from AP&L or from distributors supplied by AP&L, and its power costs exceed $7 million, which represents approximately 7% of Ricelands total annual expenses (id. at 7). Such a percentage of power costs to total expenses can be considered as making Riceland electric power intensive (Tr. 6878-80).

On the other hand, it was brought out that OCC is one of LP&L's two largest customers and that its Taft, Louisiana plant is one of the largest chemical plants in the nation. Further, electricity at OCC's Taft Plant is the most important raw material, representing about one-half of the total product cost. As the result of increasing power costs, OCC lost almost $70 million from 1978-82 and laid off 400 employees, about one-half of the total plant work force. (OCC Ex. 64, p. 36.) OCC would, therefore, be affected by the increased costs to LP&L should an equalization proposal not be adopted in this case. Moreover, electricity is a large factor in the inorganic chemicals and alkalies and chlorine industry, which represent nearly half of LP&L's industrial sales. (OCC Ex. 64, p. 34.) As in the case of Arkansas, therefore, the cost of electrical power to be sold by LP&L has significant ramifications on industrial operations in Louisiana, particularly in the chemical manufacturing area.

4. Conclusions

It is evident that the substantial swings in revenue requirements and average costs of electricity that would be occasioned by adoption of any of the various production cost allocation proposals are a major reason for the conflict that underlies this proceeding, particularly when the above described implications on industrial production in Arkansas and Louisiana are taken into account. Overall, though, none of the cost differentials or impacts are of such magnitude that they *per se* require the adoption of one proposal over another. These impacts will, however, be taken into account in making the final determination as to what constitutes a just and reasonable system arrangement.

F. Pertinent Authority Relating to the 1982 System Agreement

A review of the authority pertinent to the 1982 System Agreement can be divided into several discrete areas: (1) proceedings before Federal agencies, particularly the SEC,

the Atomic Energy Commission (AEC) and this Commission; (2) proceedings before various State commissions; (3) Commission and court decisions on rolled-in pricing; and (4) Commission and court decisions on power pooling. These areas will be discussed seriatim.

1. Federal Agency Decisions

Initially, it is helpful to review pertinent SEC cases pertaining to the Middle South System. In *Electric Light & Power Corporation*, 29 SEC 52, 62-63 (1949), aff'd, 176 F.2d 687 (2nd Cir. 1949), formation of the Middle South system was approved. In doing so, the SEC held that the four operating companies on the Middle South system had since 1930 been constructed and operated on a system-wide basis and that the system has a common dispatcher and an operating committee which forecast loads, proposes overall schedules and gives general direction to the dispatcher. Also, the SEC noted that the operating committee is composed of representatives from each of the operating companies but that the nature of their functions make them representatives of the system rather than of the individual company. Moreover, the SEC indicated that the construction requirements of the companies are formulated on a system basis rather than an individual company basis, and that determination of sites and ownership of generating facilities is decided by the most economical and efficient installation based on the system load requirements, rather than on requirements of the individual companies. *Id.* at 63.

In a later decision, the SEC concluded that the Middle South system is an integrated public utility system and noted that, in reaching this conclusion, it took into account the long historical record of the unified operations of the electric facilities, the extent of regulation by the State commissions and the fact that the system is not so large as to impair the effectiveness of regulation in the States in which the companies operate. Moreover, the SEC, in

reaching its conclusion, considered the high degree of coordination, which in part results from common control, leading in turn to common planning development. *Middle South Utilities, Inc.*, 35 SEC 1, 10 (1953).

The above discussed SEC cases definitely establish that the Middle south System is an integrated public utility system under Section 11(b)(1) of the PUHCA. However, for a holding company to be registered with SEC, the SEC must find under Section 2(a)(29) of the PUHCA, that it is an integrated public utility system. Therefore, the SEC must conclude that the system properties are interconnected or capable of interconnection, and that under normal conditions may be economically operated as a single interconnected and coordinated system. As a result, it is suggested by those opposing equalization that the findings in the SEC decisions are no more than the requisite conclusions necessary for MSU to qualify for registration as a holding company pursuant to the PUHCA.

Also, the opponents of equalization rely on other language in the 1953 SEC decision. For example, SEC noted that the construction programs for the Middle South system are coordinated through the operating committee, which meets regularly to review and estimate the system load for a period several years in advance. SEC then went on to mention that estimates are made of required system generating capabilities and of the generating capabilities of the individual companies. Then, SEC stated that, based on these estimates, the operating committee makes its recommendations to the individual companies management as to the installation of additional generating facilities and construction of transmission lines. *Middle South Utilities, Inc., id.* at 8. It is suggested that this description is consistent with the MSS testimony herein that the operating committee only makes recommendations to the MSU operating companies. In addition, it is asserted by those opposing equalization that, despite the characterizations of

the Middle South system in the SEC decisions, at no juncture is there any order or suggestion by the SEC that there should be any production cost equalization on the system.

Further, a second agency, the AEC, had occasion to consider the involvement of MSU, when the AEC made findings on whether there had been a sufficient showing that there was need for the power to be generated by the Grand Gulf nuclear facility during the construction permit hearing on that facility. In the decision of the Atomic Safety and Licensing Board (ASLB), it was noted that MP&L is a member of the Middle South system and that it is appropriate to consider the total power needs and reserve margin requirements of the system in evaluating the need for power from the Grand Gulf facility. The ASLB then held that additional generating capacity will be needed in Mississippi and the entire MSU service area to meet the projected demand for power and to assure an acceptable level of the reliability, and that the capacity of the Grand Gulf plant will be used to satisfy a portion of that need. *In the Matter of Mississippi Power and Light Co.*, (Grand Gulf Nuclear Station, Units 1 and 2), 7 A.E.C. 637, 645-46 (1974). In addition, as an alternative justification for licensing the Grand Gulf facility, the ASLB found that there could be a need for the base load nuclear generation from Grand Gulf as a substitute for gas and oil-fired units, even if the demand projections would prove inaccurate. In making this ruling, the ASLB noted that, at that time, there were current and estimated long-range difficulties in obtaining sufficient gas and oil supplies. *Id.* at 646.

Moreover, contrary to AP&L's suggestion that the ASLB's finding that the Grand Gulf Plant was needed was based primarily on the then perceived need for power in Mississippi (AP&L Reply Br. p. 95), the ASLB primary finding was that the additional generating capacity of Grand Gulf would be needed "in Mississippi *and the entire MSU service area* to meet the projected demand for power

and to assure an acceptable level of reliability" *id.* [emphasis added]. It is clear, therefore, that justification for the grant of the construction permit by the AEC in the 1974 proceeding was that the capacity from the Grand Gulf facility would be needed to meet the increasing demand for electricity in Mississippi and the increasing demand for electricity on the entire MSU system.

Regarding this Commission's decisions (both FERC decisions and the decisions of FERC's predecessor, the Federal Power Commission (FPC)), it has been consistently recognized that the operating companies are an integrated electric power system. This was indicated in *Arkansas Power and Light Co.*, 8 FPC 106, 107 (1949), and was again recognized in Arkansas *Power and Light Co.*, 34 FPC 747, 752-53 (1965), *reh. denied*, 34 FPC 1242 (1965). On appeal, the Court confirmed the Commission's determination in the 1965 proceedings, and described the MSU system as a highly integrated, interconnected pool operation, *Arkansas Power and Light v. F.P.C.*, 368 F.2d 376, 378-79 (8th Cir. 1966).

Moreover, in setting for hearing the 1973 System Agreement filed by MSS on behalf of the MSU subsidiaries, the Commission described the operating companies as utilities that are affiliates of the integrated MSU system, *Middle South Services, Inc.*, 49 FPC 1472 (1973). Also, the Commission noted that MSU and LP&L are interrelated in the rate of return case in 1977, *Louisiana Power & Light Co.*, 59 FPC 968, 977, n.14 (1977). And, in another LP&L case, where the issue was whether construction work in progress for Waterford 3 should be included in rate base, the Commission pointed out that LP&L is not an independent utility but is a wholly-owned subsidiary of MSU, thereby making it a part of the Middle South system, *Louisiana Power & Light Co.*, 13 FERC ¶61,221, at p. 61,506 (1980).

Further, in finally approving the 1973 System Agreement, the Commission in *Middle South Services, Inc.*, 16

FERC ¶61,101, at p. 61217 (1981), described the agreement as follows:

> The agreement requires each MSU operating company to have generating capacity and other facilities necessary to supply its own customer requirements. However, the Operating Committee, which is composed of members designated by each of the subsidiaries and the parent company, may also require an individual company to construct, own and operate a new generating unit of sufficient size to achieve economies of scale and help provide capacity for the projected system load. Such a new participation unit ultimately will be needed to meet the native load requirements of the individual operating company, but until the time the company load can absorb the total capacity of the new plant, its output and associated costs are shared by the other subsidiaries according to the respective capability responsibilities as defined in the Agreement. [Footnotes omitted.]

In addition, the Commission found that:

> While some rate discrimination is inherit in the MSU tariff, in theory the "short" companies will become "long" and vice versa over time such that in the long run, any discriminatory effects will cancel each other out and the result will be the economies of scale which ultimately benefit all customers of five subsidiaries. *Id.* at p. 61,221. [Footnotes omitted.]

The Commission's 1981 *Middle South Services, Inc.*, decision cited above was affirmed by the United States Court of Appeals for the 5th Circuit in *Louisiana Public Service Commission v. F.E.R.C.*, 688 F.2d 357 (5th Cir. 1982). There, the Court noted that to achieve economies of scale through the construction of large units, an individual utility may be required to construct and operate a new generating unit of sufficient size to help provide the power necessary

to meet the operating requirements of the entire MSU system, *id.* at 359. The Court further recognized that the system results in rate differences in the various jurisdictions occasioned by the natural operation of multiple regulatory systems, *id.* at 361.

Two recent initial decisions currently pending before the Commission also involved evaluation of the Middle South system. In resolving issues relating to cogeneration on the MSU system, the Presiding Judge stated that the 1982 System Agreement has twin goals: each operating company must have sufficient capacity to meet the demand of its own customers and to contribute toward meeting the demand of all other customers served by the system. It was further noted that the Operating Committee evaluates the companies' load forecasts and generating capabilities, and then makes the following determinations: when and where generation should be added; what size the unit should be; and which utilities should be responsible for constructing the unit, including arranging the necessary financing. *Middle South Services, Inc.*, 24 FERC ¶63,119, at p. 65,210 (1983). Also, the Presiding Judge recognized that the concept of economies of scale requires that generation additions be generally larger than are necessary to meet the immediate demands of the individual operating company, *id.*

More recently in *Middle South Energy, Inc.*, 26 FERC ¶63,044, at p. 65,106 (1984), the Presiding Judge found that the Middle South system is a single integrated and coordinated electric system where planning, construction and operations are conducted for the system as a whole. It was also held that the Middle South system operates without regard to company or State lines to obtain the lowest cost of power supply consistent with a high degree of reliability, *id.* at p. 65,110. After extended analysis, the Presiding Judge ordered, in ruling on the Unit Power Sales Agreement, that a form of production cost equalization be

adopted for the Grand Gulf Unit No. 1 costs, *id.* at p. 65,119-20.

Overall, the mosaic of Federal agency decisions relating to the Middle South system leaves no doubt that the system is a closely integrated and coordinated power pooling arrangement from a planning, construction and dispatch standpoint. There is, however, also a definite recognition that the individual companies have the obligation to meet the needs of their own customers. Moreover, this integrated and coordinated assessment of the operations of the MSU system is buttressed by evaluations in certain Commission studies. See for example, Power Pooling in the South Central Region, FERC-0053, (Feb. 1981), pp. 50-52 (Staff Ex. 11, pp. 50-52) and Power Pooling in the United States, FERC-0049 (Dec. 1981), pp. 124-125 (CNO Ex. 24, pp. 124-125.) Prior characterizations of the MSU system are instructive and must be taken into account in evaluating the issues at bar. They do not, however, specifically dictate that production cost equalization must be ordered for the MSU operating companies. The MSU system, as noted above, does present a picture of a highly integrated and coordinated power pooling arrangement from a planning and operation standpoint and one where all the affiliates in the power pool are wholly-owned by the parent company. Conceptionally, this does lend support to an equalization rationale, but it does not of itself constitute such an overriding consideration that it requires production cost equalization to be ordered merely because the system is so structured. Further, it is important to review certain pertinent proceedings before the State commissions, since those proceedings are also relevant to determining whether production cost equalization is warranted in this cause.

2. Proceeding Before Various State Commissions

Initially, it should be mentioned that consideration of pertinent state proceedings provides another perspective

from which to assess Middle South system operations. Most of the evidence at hearing related to proceedings on the Grand Gulf facility before the MPSC and to various proceedings before the APSC on generations additions by AP&L. The only significant discussions of matters before the LPSC related to the ruling by that Commission which allowed construction work in progress (CWIP) to be placed in rate base and on proceedings involving the Texaco refund of about $1 billion for overcharges made on gas purchased by LP&L. The record herein does not indicate that the Louisiana proceedings on either matter focused on the relationships between LP&L and other companies on the Middle South system. It should be mentioned, however, that the payment for CWIP relating to Waterford 3 nuclear facility was only borne by the Louisiana ratepayers and that the Texaco refund has only benefitted the Louisiana ratepayers. One of the reasons that there is less information on the LP&L generation additions is that, until recently, proceedings before the LPSC were not required for LP&L to secure authorization to build a generation addition. As a result, there is not the same type of formal State commission proceeding history in Louisiana that there is in Mississippi and Arkansas.

As to matters before MPSC, the focus of the evidence was on the licensing of Grand Gulf. This Grand Gulf proceeding was initiated by a joint petition filed in 1974 by MP&L and MSE, which indicated that the size of the projected unit was determined by the projected load growth of the Middle South system (MPSC Ex. 12, p. 7; OCC Ex. 48, 2nd p.). Further the basis on which MP&L and MSE founded their request for certification, was that the Grand Gulf units would become participation units under the 1972 System Agreement, under the practice where an operating company builds a generating unit in excess of its current requirements and sells the excess power to the other operating companies (MPSC Ex. 14, p. 12). Moreover, it was represented to the MPSC that MSE would become party

to the 1973 System Agreement. In addition, the documents relating to that proceeding show that MP&L's proportionate share of Grand Gulf represented by its Capability Responsibility at the time was approximately 19%. With the involvement of MSE and the presentation of data showing MP&L's projected share to be 19%, it is reasonable to conclude the MPSC was aware that the Grand Gulf facility was being constructed to meet the needs of the entire system, in addition to the needs of MP&L, when it licensed the construction of Grand Gulf in 1974.

The proceedings before the APSC reveal a different picture than that presented to the MPSC. AP&L in its Initial Brief, pp. 84-91, gives a succinct history of pertinent AP&L generation addition proceedings. This covers the nuclear units ANO No. 1 and 2, in addition to coal units at White Bluff and Independence. See AP&L Initial Br., pp. 83-91. It is not necessary to repeat that analysis in this decision, but it is sufficient to indicate that it is an accurate summary of the APSC proceedings involving those major generation additions in Arkansas.

Also, it is fair to conclude from the documents in evidence relating to these proceedings in Arkansas that, while the APSC was aware that AP&L was part of the Middle South system and that on occasions some of the generation from the Arkansas facilities might be used elsewhere on the system, nonetheless the primary concern of APSC was that AP&L have sufficient generation to meet the electrical demand in Arkansas. In contrast to the definite indication in the MPSC proceeding that the power from Grand Gulf would be used elsewhere in substantial amount, the pattern of the Arkansas cases was such that AP&L was required to justify need of the power from the facility to meet Arkansas requirements. AP&L clearly relied on the native Arkansas load to justify certification of these nuclear and coal facilities in Arkansas rather relying upon the overall MSU system load as a justification for the units. This situation is perhaps best illustrated by the fact

that, because of a lack of funds, AP&L interrupted construction of the White Bluff coal units for approximately two years from August 1975 until May 1977. During that period, AP&L received no financial assistance from MSU or the other companies to continue construction of the units. (Tr. 3292.) Again, in 1980, AP&L was faced with shutting down White Bluff Unit 2 and Independence Unit No. 1 for lack of funds and to keep construction on schedule, AP&L had to turn to AECC, a co-owner in the project, for financial aid (MSS Ex. 24, p. 14).

Similarly, it is significant that APSC gave a clear indication that it would not certificate what was originally proposed as Units 3 and 4 at the White Bluff site, since they were not necessary to meet native Arkansas load. While this decision was essentially made on environmental ground, nonetheless the indication from the APSC was that the units should not be built if they were not necessary to meet Arkansas requirements (MSS Ex. 24, p. 8). Of course, these units later became the Independence Units and were constructed at a different location but, when the Independence units were certified, AP&L again was able to justify them based upon Arkansas load (MSS Ex. 24, pp. 9-11).

Although portions of the Arkansas proceedings do establish that APSC was aware that AP&L is part of an integrated power pooling system, nonetheless AP&L was consistently required to justify construction of facilities based on need in Arkansas and had to comply with Arkansas law governing financing such facilities.

3. Decisions on Rolled-In Pricing

The proponents of cost equalization, particularly the Commission Staff and OCC, rely for support of their position on a line of cases that deal in one aspect or another with the issue of whether to roll together the cost of subsidiaries for the purpose of calculating cost of service. In this regard, the following cases are cited: *Wisconsin*

Michigan Power Company, 31 FPC 1445 (1964); *St. Michaels Utilities Commission v. Eastern Shore Public Service Company of Maryland,* 35 FPC 591 (1966), rehearing denied, 35 FPC 1027 (1966), aff'd *St. Michaels Utilities Commission v. F.P.C.,* 377 F.2d 912 (4th Cir. 1967); *Georgia Power Company,* 52 FPC 1343 (1974), *reh. denied,* 54 FPC, 1103 (1975); *Connecticut Light and Power Company,* 59 FPC at 811 (1977), *aff'd* on *reh.,* 55 FPC 1986 (1976); *Ohio Power Company v. F.E.R.C.,* 668 F.2d 880 (6th Cir. 1982); and *Nantahala Power and Light Company,* 19 FERC ¶61,152 (1982), *reh. denied,* 20 FERC ¶61,430 (1982), 21 FERC ¶61,222 91982), *aff'd Nantahala Power Light Co. v. F.E.R.C.,* 727 F.2d 1342 (4th Cir. 1984). While in none of these cases was rolled-in pricing for affiliates' transactions ordered, they do represent authority that the Commission has the power to order rolled-in pricing of subsidiaries' costs in determining cost of service, where circumstances so warrant.

In addition, it is correct, as the opponents of equalization point out, that rolled-in pricing has been used principally in transmission and subtransmission areas, *Public Service Company of Indiana v. F.E.R.C.,* 575 F.2d 1204 (7th Cir. 1978); *Potomac Edison Electric Co.* , 20 FERC ¶63,060, *aff'd,* 23 FERC ¶61,106 (1983), 23 FERC ¶61,398 (1983); *Southern California Edison Co.,* 20 FERC ¶61,301, at p. 61,589 and *Florida Power and Light Co.,* 56 FPC 3581 (1976). Moreover, it is noted by those opposing equalization that the rolling in of generation costs of separate utilities in a power pool has never been ordered by the Commission.

Of the cases cited, it is warranted to focus attention on *Georgia Power Company,* 52 FPC 1343 (1974), because of the similarity of the circumstances in *Georgia Power* and the instant case. Georgia Power Company (Georgia Power). Alabama Power Company (Alabama Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) were operating utilities in Georgia, Al-

abama, Florida and Mississippi. All were wholly-owned subsidiaries of the Southern Company. The Commission found that the Southern Company designed and installed both generating and transmission facilities and operated the four subsidiaries as an integrated electric utility system, and that Georgia Power and Alabama Power had been interconnected as early as 1920 and centrally coordinated since 1950. *Id.* at 1347.

Before the Commission in *Georgia Power* was a tariff for the sale of power and energy at wholesale to eighty-nine customers of Georgia Power. One of those wholesale customers opposed a proposed settlement accepted by the other eight-eight. That customer contended that, because Southern's pool is integrated, bulk power supply costs should be allocated to Georgia Power customers on a pool basis rather than on an individual company basis. *Id.* at 1346-47.

In disposing of *Georgia Power,* the Commission ruled that the conventional approach of costing electric service on an individual company basis had not been shown to be unjust and unreasonable, *id.* at 1348, even though the Southern Company operated its four subsidiaries as an integrated electric utility system, used a computerized economic dispatch system for coordinating available energy sources to meet the Southern pool requirements and scheduled bulk power deliveries to meet needs not only of the Southern Pool members but also of outsiders to whom the individual members sell energy, *id.* at 1347. It was also brought out that the Southern Company affiliates have separate identities, managements and service areas; that they maintain final control of their power generation even though it is centrally dispatched; that they plan and install capacity for their own needs as well as for those of the pool; and that they record and bill intercompany transactions, *id.* at 1348. There is, therefore, a striking similarity between *Georgia Power* and the case at bar and it

is clear that the Commission declined to order system-wide costing in *Georgia Power*.

There are, however, certain further statements in *Georgia Power* that merit attention. For example, the Commission recognized a distinction between a power pool owned by a single holding company and one comprised of independent entities, although it did note that issue before it was whether to treat low cost hydrogeneration and transmission from Georgia Power's sister company in Alabama in such manner so as to benefit wholesale customers in Georgia, *id.* at 1349. The Commission further pointed out that the case involved only Georgia Power's customers and that no evidence had been produced concerning the effects on Alabama Power's customers and that it did not have jurisdiction over Alabama Power retail rates. The Commission did infer, however, that the lowering of generation and transmission costs of bulk power by utilizing the rolled-in technique would result in higher allocated cost to retail service in Alabama and that this shift of higher cost to alabama service would not be related to the cost of providing retail service in Alabama. *Id.* The Commission then concluded:

> The test to be applied then is whether we could adopt cost-allocation techniques as fair and reasonable when these techniques, if uniformly applied to all services rendered by the utility, produce rates which are not based upon costs related to the service rendered. If we had jurisdiction over the utility's retail business in Alabama, it is most doubtful that we would prescribe rates there based on costs not related to the rendition of service. *Id.*

The Commission, however, did observe in *Georgia Power* that, if electric utilities become more dependent on large multi-company generating units which are remote from their service areas, it may become necessary to treat rate-making on a broader geographic basis. The Commission

then observed that, at the time, Georgia Power was generating approximately 75% of the electrical energy which was available to it in the test year, so there was no basis for finding the conventional approach unjust and unreasonable. *Id.*.

In the instant case, 92.5% of the energy requirements of AP&L in 1982 was provided by AP&L generation, plus the purchase from Southwestern Power Administration for the benefit of Reynolds Metal Company, AP&L Form 1, 1982, p. 401. In addition, the Grand Gulf and Waterford 3 nuclear stations are being constructed in the service territories that are presently short of such base load capacity, although it is clear that the Grand Gulf power is intended to be used throughout the system. Further, the Commission noted in *Georgia Power, supra* at 1349, that it was entirely fortuitious that the cheap hydroelectric capability was located in Alabama rather than in Georgia and that the Southern Company had done nothing illegal in establishing separate entities to operate in various states.

Moreover, the Commission in *Georgia Power, id.* at 1349-50, considered the effect that utilizing rolled-in costing would have on the authority of the State regulatory commissions, when it stated:

> Were we to accept the Municipal's rolled-in theory, the authority having jurisdiction over Alabama Power Company's retail rates would be legally free (and probably honor bound) to ignore our allocation and determine retail rates on the basis of Alabama Power company's costs. In a similar situation we would do so. We have never permitted costs properly borne by others to be imposed upon the ratepayers under our jurisdiction. The practical effect of the adoption of Dalton's rolled-in theory will be a subsidization by The Southern Company of power costs to wholesale customers in Georgia. We find no basis to so require.

The Commission's indication that the State authority with jurisdiction over retail rates would be free to ignore the FERC allocation is not valid in light of later authority embodied in the *Narragansett* doctrine. In *Narragansett Electric Company v. F.E.R.C.*, 119 R.I. 559, 564-65, 568, 381 A.2d 1358, 1361, 1363 (1977), *cert denied.* 435 US 972 (1978), it was established that once FERC allows the owner of a plant to charge the sponsoring utilities a rate reflecting the investment in that plant, the State commission with regulatory authority over the utility is required by the Supremacy Clause of the United States Constitution to allow the utility to recover the cost of the FERC approved rate in the retail rates. *Narragansett* has been followed in *Washington Gas Light Company v. Public Service Commission,* 452 A.2d 375, 386 (D.C. App. 1982), *cert denied,* 103 S. Ct. 2454 (1983); *Eastern Edison Co. v. The Department of Public Utilities,* 388 Mass. 292, 446 N.E.2d 684, 690 (1983); and *Northern States Power Co. v. Hagen,* 314 N.W. 32, 38 (N.D. 1981).

In evaluating *Georgia Power,* is is first pertinent to note that the Commission did not order rolled-in costing but stayed with the conventional method of having the cost of each company determined individually in setting the wholesale rates. It is, however, appropriate to point out that, in the case at bar, we are not dealing with rates to wholesale customers as were involved in *Georgia Power.* Also, while the principles enunciated in that case are certainly applicable in the case at bar, nonetheless, the focus here is on transactions among the operating companies themselves. Further, it is clear under the *Narragansett* doctrine that those transactions, if approved by FERC in setting the formula rates under the 1982 System Agreement, would have a binding effect on the State commissions in setting retail rates. Moreover, in the present case, there is more information than in *Georgia Power* on the impact of equalization ratepayers in the various jurisdictions, as discussed in Section VI E, *supra.* This case, there-

fore, has a different perspective than the *Georgia Power* case.

Moreover, it is clear that the Commission by implication in *Georgia Power* recognized its authority to impose system-wide costing if the circumstances so warrant. While the Commission did not do so under the facts of *Georgia Company,* the issue that must be considered in this action is whether the factual and legal circumstances relating to the Middle South system warrant the imposition of production cost equalization, which constitutes a form of rolled-in costing.

G. Analysis and Resolution of the Production Cost Allocation Issue

Based on all the evidence of record and on the factual and legal evaluations presented above, an analysis and resolution of the key production cost equalization issue can now be made.

At the outset, it should be reiterated that the Commission has clear authority, under Sections 201(a) and (b) of the FPA, 16 U.S.C. §§824(a) and (b), over the 1982 System Agreement since that Agreement involves sales of electrical energy at wholesale in interstate commerce. Moreover, to implement its jurisdiction, this Commission has the power under Sections 205 and 206(a) of the FPA, 16 U.S.C. §§824 d and e(a), to revise the 1982 System Agreement by adopting any of the alternate production cost allocation proposals presented herein or by otherwise reforming that Agreement so that it will result in just, reasonable, non-discriminatory and non-preferential rates for the Middle South system pooling transactions, if it is in the public interest to make such revision.

Moreover, there is no bar to the Commission exercising its jurisdiction to revise the 1982 System Agreement as discussed above, arising from the *Mobile-Sierra* doctrine, from the effects of a revision on State ratemaking au-

thority, from the PUHCA or from any of the other alleged impediments to the alternate production cost allocation proposals.

However, in reaching a determination on production cost allocation, due deference must be given to State regulation in light of the statutory scheme of Sections 201(a) and (b) of the FPA. Also, appropriate consideration must be given to the economic impacts of the various proposals, although none are of such a magnitude that they constitute a controlling factor. In addition, attention must be paid to the proceedings before the Federal and State agencies, even though the review thereof did not conclusively establish that any one method of production cost allocation should be adopted. And, of critical importance is the assessment that must be made of the operation of the Middle South system and of its practice with regard to generation additions, since these are key elements in determining where cost responsibility should lie.

Further, it should be noted that the authority relating to power pooling does not contain any binding precedent that dictates the result to be reached herein. It does reveal, however, that the Commission has the power, in fulfilling its statutory responsibilities under the FPA, to order any of the production cost allocation methodologies, including production costs equalization, if circumstances so warrant, that is, if to do so is necessary in the public interest to achieve just, reasonable, non-discriminatory and non-preferential rates in the Middle South System Agreement.

For assessment purposes, the MPSC proposal can be dealt with individually and it will be covered first. Then the 1982 System Agreement methodology and the equalization proposals (considered together in light of the resolution reached *infra*) will be evaluated in the context of overall operation on the Middle South system. In the latter regard, the factors noted above as being of decisional sig-

nificance will be taken into account. Finally, the circumstances surrounding the planning, ownership and construction of the Grand Gulf nuclear facility merits special attention, as will be discussed *infra*.

1. The MPSC Proposal

As discussed above, the MPSC proposal is to reinstate the 1973 System Agreement with its participation unit concept for equalizing excess capacity, but with a modification to make MSE a party to the Agreement, so that the Grand Gulf facility would become a participation unit (MPSC Initial Br., pp. 5-6). Two arguments raised by MPSC warrant comment before turning to the merits of the MPSC proposal.

First, MPSC asserts that none of the other production cost allocation proposals can be adopted since that would exceed the scope of FERC authority as set out in Section 201(a) of the EPA, 16 U.S.C. §824(a), as well as being contrary to the 10th Amendment of the United States Constitution, since adoption of the other proposals would displace State decisions regarding new power plants and would substitute Federal policy for State regulation of retail rates (*id.* at 51-55). The arguments relating to Section 201(a) of the FPA have been previously discussed in detail and must be rejected for the same reasons set out in Section VI D 3, *supra.* MPSC does not explain in detail its argument regarding violation of the 10th Amendment of the United States Constitution, which reserves to the States powers not delegated to the United States by the Constitution nor prohibited by it to the States. However, the rationale for this argument appears to be the same as the MPSC rationale relating to the FPA, and the 10th Amendment argument is likewise unpersuasive.

In addition, MPSC asserts that the other proposals are barred by the doctrine of equitable estoppel. MPSC claims that its decision pertaining to the need and economic justification for Grand Gulf was made in reliance on repre-

sentations by MSE and MP&L that the power and energy from Grand Gulf in excess of MP&L's service area needs would be sold to other companies on the System. MPSC contends that the 1982 System Agreement and the cost equalization proposals would reach different results from the representations made regarding costs associated with excess capacity, which allegedly were relied upon by MPSC, and will cause higher costs for Mississippi ratepayers than were represented to and considered by the MPSC. Therefore, MPSC suggests that these proposals cannot be adopted based upon the doctrine of equitable estoppel. (MPSC Initial Br., pp. 45-51.) MPSC relies upon *F.P.C. v. Colorado Interstate Gas Company*, 348 U.S. 492, 502 (1955) and *Florida Power and Light Company v. F.E.R.C.*, 660 F.2d, 668, 679 (5th Cir. 1981), for the proposition that he doctrine of equitable estoppel can be applied in FERC matters involving the FPA. In essence, MPSC argues that this Commission is precluded under the doctrine of equitable estoppel from adopting an allocation methodology different than the methodology allegedly relied upon by MPSC in certifying Grand Gulf, that is, the participation unit arrangement.

The MPSC equitable estoppel argument, however, is not well taken. First, the conditions for the application of equitable estoppel are not present. Equitable estoppel cannot bind parties who made no representations to the MPSC, so the only parties that could conceivable be bound are MSE and MP&L. Certainly, this Commission could not be impeded, by operation of the doctrine of equitable estoppel, from fulfilling its public interest obligation under the FPA to ensure that the 1982 System Agreement result in just and reasonable rates, particularly where that doctrine would result in an inequitable result, as will be discussed *infra*.

Further, MPSC could not have reasonably relied on representations as guarantees against modification in the System Agreement. Such reliance would have been

unreasonable because this Commission, not the MPSC, has jurisdiction over the System Agreement. Since MPSC either was aware or should have been aware of this situation, representations made by MP&L and MSE could in no way bind this Commission from taking appropriate action with regard to the System Agreement and changing the arrangements there under if to do so is required by the public interest obligations imposed on the Commission by the FPA. The Presiding Judge in the Unit Power Sales Agreement case, *Middle Energy, Inc.*, 26 FERC ¶63,044 (1984), previously rejected a similar argument by MPSC. There, the representations made by MP&L and MSE regarding the allocating of Grand Gulf under the 1973 System Agreement were noted, but the Presiding Judge pointed out that MPSC did not approve any particular allocation or allocation methodology for Grand Gulf. It was then held that MPSC did not have any authority to approve an allocation or allocation methodology since those matters are subject to FERC review and approval under the FPA. *Id.* at pp. 65,111-12. This reasoning is equally applicable in this cause and any reliance by MPSC on representations by MSE and MP&L about allocations or allocation methodology would have been misplaced since they are subject to alteration under FERC review. As a result, the doctrine of equitable estoppel does not apply in this proceeding.

As to the merits of the MPSC proposal, the following pertinent facts must be taken into account. First, if the MPSC proposal were to be adopted, Grand Gulf Unit 1 would become a floating participation unit, the responsibility for which would shift from company to company as the companies become short or long, or shorter or longer. The power from the Grand Gulf facility would thus be paid for and received by the companies who are long under the System Agreement.

Since MP&L is currently a long company and is expected to remain so until at least the 1990's, it would

avoid all responsibility for Grand Gulf during that time (MPSC Ex. 1, pp. 17-18). At some time in the 1990's MP&L would need some power from Grand Gulf and have to pay the costs thereof, but would also receive the energy entitlement represented by its share of the plant. The result would be that for approximately a 10-year period, LP&L and NOPSI, the short companies, would pay approximately $3 billion of the Grand Gulf costs and, thereafter, MP&L would enjoy benefits from the project in its later, less expensive years (Tr. 4130, 4168). This would permit MP&L to avoid the high front-end costs of Grand Gulf and then secure power from the facility after depreciation has substantially reduced its cost. For example, the cost per kW for Grand Gulf decreases by 20% over the first six years (MPSC Ex. 5, p. 1). MPSC concedes that it will not need Grand Gulf to meet its own capacity responsibility until at least 1990 (Tr. 4609), so MP&L will have the advantage of taking its share of the unit after it has been initially depreciated.

In addition, the MPSC proposal does not meet the objective in Section 3.02 of Article III of the 1982 System Agreement that each of the operating companies should attempt to secure nuclear and coal-fired generation. Therefore, the MPSC proposal would not tend to achieve the goal of the operating companies diversifying their fuel mix. At present, MP&L is operating with only 400 MW of coal-fired capacity, which was purchased from AP&L in order to diversify MP&L's fuel mix. Moreover, MP&L was already a long company when it arranged for the purchase. (Tr. 4669-78.) It is apparent that MP&L would, under its proposal, seek to avoid responsibility for the more expensive up-front cost of Grand Gulf for an extended period, while diversifying its fuel mix by other less expensive means, such as the purchase of coal-fired capacity.

Further, MSS and LPSC both indicated that the MPSC proposal would be inequitable (Tr. 2015-16, 2762, 4167) and even MPSC recognized that the inequity inherent in

its proposal is a difficulty (Tr. 4721-22). MPSC did point to certain modifications that might alleviate the inequity, such as use of a levelization procedure, but MPSC did not advocate adoption of such a procedure herein (Tr. 4685).

In assessing similar arguments made by MPSC for reinstatement of the participation unit procedure in the Unit Power Sales Agreement case, the Presiding Judge in *Middle South Energy, Inc., supra*, at p. 65,112 reached the conclusion that the results achieved by the MPSC proposal, where MP&L would grow into its allocation of Grand Gulf without having to incur the high front-end capital costs of the facility, would be unfair and unduly discriminatory. That same conclusion must also be reached in the instant case. Accordingly, the MPSC proposal must be rejected as not being just and reasonable since it would produce inequitable and discriminatory results.

2. Overall Middle South System Operations

There emerges from the evidence presented a distinct picture of the history and development of transactions between the operating companies on the Middle South System since its formation in 1949. The system is a highly integrated, interconnected electric system and has been so operated both before and subsequent to its modern inception in 1949. Further, power flows throughout the system from the most economical sources through the use of common dispatch, and the cost of producing electricity has been made less expensive by the various operating companies taking advantage of economies of scale, that is, by building larger plants than were immediately needed on their particular system and selling the excess electricity to their sister system companies, until the building utility grew into the plant. Further, this integration and interconnection of the system has increased the reliability of the entire system, as well as the reliability of the individual operating companies.

The pattern of intercompany transactions has been as follows: Under the 1951 System Agreement, reserve equalization transactions among the operating companies were based on $1.15 per kW regardless of the cost of the plant producing the excess kW; under the 1973 System Agreement, the participation unit method was employed, where the capacity and energy of the last plant on line of the long company, in most instances the highest cost plant on the long company's system, was sold to and paid for by the short companies; and, under the 1982 System Agreement, reserves are now equalized based upon the capacity costs of the long company's intermediate units, with no energy entitlement associated therewith. Never during the modern history of the system (1949 on) has there been any arrangement governing intercompany transactions where all the costs of the production plants of the operating companies have been combined and then allocated to the respective operating companies based on some capability responsibility formula.

In light of the above, the adoption of any of the production cost equalization proposals would present a dramatical departure from the former operation of the Middle South system insofar as intercompany transactions are concerned. Equalization would totally change the former practice of the operating company with excess capacity selling that capacity, on a reserve equalization basis, to the companies with insufficient capacity until such time as the excess company has need for the power from the particular plant involved to meet needs in its own jurisdiction. At no juncture during the modern history of the Middle South system has there been any suggestion that there be system plants, the costs of which would be allocated to all of the operating companies, with, of course, the lone and notable exception of the Grand Gulf nuclear facility that will be discussed *infra*.

Further, despite the mass of evidence and examination about the terminology in the System Agreement, about

the actions taken and language used at various board and Operating Committee meetings, and about common directors and officers of MSU and its subsidiaries, the only first hand, personal knowledge of the actual operations of the Middle South companies was presented by MSS. That MSS evidence reveals a pattern of autonomy on the part of the individual operating companies, particularly as to a specific plan site locations, fuel and financing. The overall tenor of the MSS evidence negates the contention that Middle South is a single, monolithic system run by MSU. This first hand data also indicates that generation additions in almost every instance (except for Grand Gulf) were made primarily to satisfy individual company needs. It further establishes the historic pattern on the system of a company building a plant in excess of its present needs and selling the excess to its sister companies until the building company gives into the plant. The historic pattern allowed the system, as the MSS evidence shows, to achieve economies of scale ad reliability not obtainable on an individual company basin.

Moreover, while it is true that the production cost equalization proposals would meet many of the objectives in the 1982 System Agreement, particularly the goal of each company having a proportionate share of coal and nuclear units available to serve its customers (see Section 3.05 of Article III of the 1982 System Agreement), the system has not ever, either at the direction of MSU or through agreement among the MSU companies, voluntarily moved to implement that objective in the System Agreement through pooling the costs of either coal or nuclear-based generation or all production generation facilities, and then allocating those costs to the individual operating companies based upon some responsibility allocation formula. In addition, there is the definite obligation in Section 4.01 of Article IV of the 1982 System Agreement, that each individual operating company normally own or have available to it

under contract, generating capability and other facilities to supply the requirements of its own customers.

Under the above circumstance, to revise the 1982 System Agreement by ordering production cost pooling and equalization constitutes a drastic deviation from past practices on the system relating to intercompany transactions and would change the underlying nature of such transactions. It is correct that it was established on the record, based on factual data, agency decisions and court cases, that the Middle South companies constitute a highly integrated electric system, with common planning and central dispatch, for the purpose of achieving economies of scale and enhanced reliability. However, the MSU companies have never been operated as a single system where all the generation is shared and responsibility therefor allocated to the operating companies. Therefore, to make such a fundamental change would be a quantum leap and would amount to a revision of the entire Middle South system in a manner not consistent with the history of operation on the system. Such a basic change is not justified merely because the Middle South system is highly integrated and coordinated.

The inquiry is not ended, however, since consideration must be given to whether there are recent circumstances that would warrant the substantial revision of the Middle South system represented by production cost equalization. In this regard, the history of operations on the Middle South system during the 1950's and 1960's reveals that the reserve equalization made at a set price between the long and short companies resulted in a rough form of equalization because the cost of producing the KW involved did not vary greatly. Further, when the 1973 Agreement became effective with its participation unit concept, there were cost disparities, since the last unit of the long company, the participation unit, was generally more expensive from a capacity standpoint, but the busbar, or total costs, of the participation unit were generally comparable to such

costs for other units on the system. And, since the short company was entitled to receive energy from the participation unit, again a certain rough cost equalization pattern was maintained. However, in the 1970's and the early 1980's, certain circumstances occurred that constitute the underlying reasons for the current conflict over the 1982 System Agreement.

First, the use of coal and nuclear for generation, which became part of Middle South's production planning in the late 1960's, was given a very substantial impetus by gas curtailment in the early 1970's and by the oil embargo of 1973, which cast a dark shadow over oil and gas-fired generation from a reliability and cost standpoint (MSS Ex. 4, p. 2). As a result, the 1982 System Agreement shows a shift in emphasis to have the operating companies move toward nuclear and coal-fired generation. However, the demand for electricity on the system not only did not grow at the projected rate of the Middle South's forecasts but, indeed, flattened to such an extent that currently there are approximately 40 to 50% reserves on the Middle South system. Therefore, the system is now in the position of having a variety of plants under construction and/or about to come on line (such as Grand Gulf and Waterford 3) which will not be needed within the time frame originally predicted based on the earlier demand projections. This drastic demand change was coupled with soaring construction costs, particularly for nuclear plants such as Waterford 3 and Grand Gulf that took extended periods of time to construct. As a result, not only is the Middle South system today faced with an overabundance of reserves but it also must deal with two very expensive nuclear units, which will cost approximately three billion dollars apiece and will come on line at over $2500 per kW for their capacity costs. As has been noted above, these two plants will generate only approximately 13% of the electricity to be used on the system but they represent over 70% of costs for production plant on the Middle South system.

The two nuclear plants will also, when they come on line and go into rate base, cause the retail rates and the rates to the wholesale customers to rise substantially in the affected jurisdictions.

On the other hand, the parties opposing equalization suggest that these cost disparities relating to the two new nuclear power plants are not necessarily out of line with the prior disparity in costs that occurred when the Arkansas ANO nuclear units came on line. It is argued that to equalize all production costs at this juncture would be a redistribution of the economic benefits flowing to the Arkansas ratepayers from their lower cost units to ratepayers in the other jurisdictions, and that such redistribution should not be accomplished by regulatory fiat.

On this latter point, the proponents of equalization point out that Arkansas during the 1950's, the 1960's and a large portion of the 1970's, relied on low cost gas production, particularly in Louisiana, to meet Arkansas needs. Therefore, they assert that now that Arkansas is in a favorable position, it should be willing, from an equity standpoint, to share its relatively low cost nuclear and coal generation by implementation of a production cost equalization proposal.

Regarding cost disparities and economic impacts, which are discussed in detail primarily in Section VI E, *supra*, it should be noted that none of the differences brought out on the record are so compelling that they require the adoption of one form of production cost allocation. The revenue requirements evidence could be interpreted as favoring AP&L and the Arkansas interests while the annual average costs of electricity data lends support to an argument favoring equalization. And neither the industrial impacts in Arkansas nor those in Louisiana present controlling reasons for adopting a particular production cost methodology. In any event, the bottom line is that the ratepayers on the Middle South system will have to absorb

the substantial cost of Waterford 3 and Grand Gulf in some fashion, and cost disparities between the jurisdictions is inevitable no matter what plan of allocation is approved. In addition, it is conceivable that, in the long run, these two nuclear units may not be considered excessively expensive when the electrical demand eventually catches up with the excess capacity and even more expensive future units are required to be built on the Middle South system. As a result, what now appears to be an economic burden could turn into a substantial benefit depending on future circumstances.

Moreover, it must be pointed out concerning cost disparities and economic impacts, that the disposition herein regarding Grand Gulf will ameliorate the cost disparities and economic impacts. For the reasons discussed *infra,* equalization of Grand Gulf's production costs is warranted and this results in one of the new expensive nuclear plants being spread among all the operating companies while the other, Waterford 3, will be handled under the terms of the 1982 System Agreement as proposed by MSS. Therefore, this should result in economic differences at about the mid-point of those shown for the 1982 System Agreement and the equalization proposals on MSS Exhibits 19, 20, 21, 23, 59, 60, 61 and 63.

When all of the above factors are taken into account, it is not warranted at this time to order production cost equalization on the Middle South system. The reasons for this conclusion are as follows. First, in light of the disposition of Grand Gulf nuclear facility discussed *infra,* cost disparities on the system will not be nearly as great as would have resulted had the 1982 System Agreement been adopted without the treatment ordered herein for Grand Gulf or had some form of production cost equalization been ordered. While some cost disparity will result when Waterford 3 comes on line and goes into rate base, this disparity does not warrant the substantial revision of the intercompany transactions on the Middle South system that would

result from adoption of a production cost equalization proposal. Analogously, the size of the rate benefit the Louisiana ratepayers secured from the Texaco refund does not, of itself, justify sharing that benefit with the other jurisdictions on the Middle South system. Further, since production cost equalization would be inconsistent with the history of intercompany transactions on the Middle South system, there is a strong factual reason for not restructuring the system to meet the current cost disparity problems.

Another compelling factor against equalization is that Federal regulation is meant to be supplemental to, not to supplant, State regulation. The ordering of production cost equalization would dramatically affect rate base in the States involved, to such an extent, for example, that approximately 75% of AP&L's rate base would be affected by production cost equalization. There is, therefore, a strong policy reason for not invading the State commission's authority to set retail rate by assuming Federal control over such a large portion of AP&L's rate base. Under the *Narragansett* doctrine discussed *supra,* the State commissions would be required to reflect the plant placed in rate base at the wholesale level in their retail rates, so the practical effect of ordering production cost equalization would be to bind the local State commissions in many of their rate base determinations. Under the statutory scheme of the FPA, this effect should be avoided unless there are compelling reasons to exercise such Federal authority in the current case. While the reasons favoring equalization are not unsubstantial, they are not so compelling that they justify the extensive intrusion into an area normally subject to regulation by the State commissions.

A further factor that operates against production cost equalization is that the companies of the Middle South system in seeking certifications made certain representations to the State commissions, and to change those representations substantially at this time is undesirable unless

there is sound justification therefor. In this regard, APSC established that the certificates of convenience and necessity sought to build AP&L plants were justified on the basis that the power was needed to meet the demands of ratepayers in Arkansas, and not to meet system needs. MPSC also brought out that the percentage of ownership of MSE and its use as a participation unit under the 1973 System Agreement were factors used by MSE and MP&L to secure a certificate of convenience and necessity to construct the Grand Gulf facility. MPSC avers, therefore, that the change to another system of allocation of capacity costs and energy from Grand Gulf is not warranted. While, for reasons discussed, *supra,* the MPSC claim must be rejected, due consideration must nonetheless be given to the APSC position and to maintaining the integrity of the APSC process, if such a result can be equitably achieved.

In light of the above analysis, it must be concluded that the production cost equalization proposals should be rejected at this time and that the 1982 System Agreement should be approved as proposed with regard to its reserve equalization provisions. However, the Grand Gulf nuclear facility must, for reasons stated, *infra,* be considered separately and the issues relating thereto resolved on an individual basis. The Grand Gulf resolution must then be integrated to be consistent with this basic ruling approving the adoption of the 1982 System Agreement.

3. The Grand Gulf Anomaly[1]

The facts surrounding the planning, licensing, and construction of the Grand Gulf nuclear facility show that it

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[1] An argument can be advanced that no disposition should be made herein of Grand Gulf since jurisdiction over that facility resides in the Unit Power Sales Agreement proceeding, Docket No. ER82-616-000. However, assessment of Grand Gulf is vital to resolution of the production cost allocation issue in this cause and its allocation represents a critical link in the pooling arrangements on the Middle South system. Since the 1982 System Agreement is the basic document controlling

is a definite exception to the general practice relating to generation additions on the Middle South system. As discussed above, generally an MSU operating company would build a plant somewhat larger than its existing needs, sell the excess to its sister companies and then grow into the plant. Grand Gulf from its inception was planned, presented to the licensing authorities and constructed as a system plant not only to serve the needs of MP&L but to serve the needs of all the operating companies on the system.

The chronology of the planning of Grand Gulf set out in Section VI C, *supra,* makes this apparent. Initially, in 1971, it was agreed by the Operating Committee that two units that later became Grand Gulf Units 1 and 2, would be built by MP&L and NOPSI, respectively. (Tr. 1541). The unit that became Grand Gulf 2 was to be constructed by NOPSI but, because of a study showing the site not to be suitable because of cost considerations, that unit was moved to the Mississippi Grand Gulf site (LPSC Ex. 40; Tr. 1541-43, 2536-38). Further, at the September 1972 Operating Committee meeting, when MP&L recommended that the NOPSI unit become Grand Gulf Unit 2, MP&L also indicated that it could not on its own finance one unit, let alone two (LPSC Ex. 41, Tr. 1542-46, 1562). As a result, there were discussions on the alternatives of (1) having Grand Gulf jointly owned and financed by the operating companies or (2) forming a generating company to own and finance the Grand Gulf facility (Tr. 1546-47). Following a study by the financial departments of the companies on these alternatives, the Chief Executive Officers of the MSU companies decided to use a generating company rather than joint financing for Grand Gulf (Tr. 1556). To effectuate this decision, MSE was formed in the 1973-

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those pooling arrangements, it is appropriate to deal with Grand Gulf in this proceeding. In any event, this argument will be academic at the Commission level since the Commission has both of the dockets involved before it for disposition.

74 time frame as a generation subsidiary of MSU to own and finance Grand Gulf Units 1 and 2 (Tr. 1557-58, 2434), with MP&L serving as MSE's agent for construction and operation of the facility (Tr. 2548).

Another point that is important is that the decision to proceed with Grand Gulf Unit 2 was based on the combined load forecasts of all the companies (Tr. 1547-48). Also, in September 1970, MP&L's interest in a nuclear unit was to diversify its fuel mix since MP&L was being forced to burn oil because of gas curtailment. The specific size of the nuclear unit was not discussed at that time (Tr. 1531.) Moreover, the July 1971 ten year load and capability forecast was in effect when the Operating Committee agreed that the MP&L nuclear unit (which became Grand Gulf Unit 1) was to come on line in 1979 (Tr. 1532, 1534, 1541). That forecast covered the 1971-80 period (Tr. 1538) and projected MP&L's peak load to be 2675 MW in 1979, which, with a 16% reserve, made MP&L's projected requirements approximately 3100 MW for 1979 (Tr. 1534-36). As to capacity, MP&L in 1971 had 1220 MW, and additional plants of 750 MWs and 700 MWs were to begin operation in 1972 and 1975, respectively. This on line and projected capacity, coupled with the 1250 MWs of Grand Gulf 1, would have given MP&L 3920 MW of capacity in 1979. (Tr. 1535.) This would have made MP&L about 820 MWs long in 1979, with approximately 36% reserves. It is reasonable to conclude from this that diversification of fuel mix was MP&L's main reason for volunteering to build Grand Gulf Unit 1, and that MP&L and its sister companies knew that about two-thirds of Grand Gulf Unit 1 (820 of 1250 MWs) would be used for an extended period to meet system needs, even based on the 1971 forecast. The 1973 System Agreement was being prepared in 1971 and MP&L could anticipate that Grand Gulf Unit 1 would be a participation unit (Tr. 1537), but MP&L would not have grown into the unit even by 1980, the last year of the forecast. While it might have then been considered

that MP&L would have grown into the unit by 1982, if the 1971 forecast was extended using the growth rate of 7 1/2 to 8% extant at that time (Tr. 1537-38), it would have been obvious that this growth rate was totally unrealistic by the mid to late 1970's. Accordingly, with the concomitant delays and rapidly escalating costs for Grand Gulf Unit 1, that were experienced in the 1970's, it is fair to conclude that the prime justification for proceeding with Grand Gulf Unit 1 was to meet system needs, not to satisfy MP&L demand. Moreover, this conclusion is buttressed by the fact that, at present, MP&L will not need *any* power from Grand Gulf until the 1990's (MPSC Ex. 1, pp. 17-18), and it was not shown when, if ever, that MP&L might totally grow into Unit 1, that is, use all of its generation for MP&L needs.

It is also worth noting that, when MSE was conceived, there was consideration given to placing all future base load plants, except certain specific units then under construction, under MSE ownership, thereby eventually achieving production cost equalization (Tr. 2595, 2701). This plan did not materialize, however, and MSE's sole asset is the Grand Gulf nuclear facility. Moreover, there are currently no plans by MSU to effectuate production cost equalization now or in the future by having MSE own all production plant on the system or by having it own all new production plant.

In addition, not only does the planning of Grand Gulf show that it is a system facility to be owned by a special subsidiary formed to finance it, but its licensing was in marked contrast to the licensing of other production plants by the operating companies. For example, the applicants before the MPSC Commission were MSE and MP&L in securing its certificate of public convenience and necessity to construct the plant. (MPSC Exh. 12). Also, the involvement of MSE as owner and financer of the plant was made clear to the AEC, which approved construction of the plant at the Federal level, since MSE was a coapplicant

for the Grand Gulf facility before the AEC, *Mississippi Power and Light Company, et al.* (Grand Gulf Nuclear Station Units 1 and 2), 8 AEC 339, 340 (1974)). It was established in the AEC proceeding that the financing of Grand Gulf facility was to be undertaken by MSE based upon the entire system's assets, as opposed to being based upon MP&L's assets, *id.* at 341. The two Grand Gulf units were projected to cost $1.3 billion and MP&L's assets at that time were only approximately $475 million, while MSU then had assets of $2.7 billion, id.

Further, the State and Federal licensing proceedings show that Grand Gulf was to be used to meet system needs. This was specifically held by the AEC's Atomic Safety and Licensing Board in its construction permit decision on environmental issues, *Mississippi Power and Light Company,* (Grand Gulf Nuclear Station Units 1 and 2), 7 AEC 637, 645-46 (1974). It was also brought out before the MPSC that MSE was constructing Grand Gulf to make power available to all the system operating companies (MPSC Ex. 12, pp. 2, 9, 10; MPSC Ex. 39, pp. 1, 2).

This Grand Gulf licensing presents a very different picture, for example, from the Arkansas licensing cases, proceedings where AP&L justified the certificates for construction of its various operating plants such as the ANO, White Bluff and Independence units based upon the need for power to serve Arkansas demand. Also, the financial presentations before the APSC reveal that AP&L would finance construction of the units. It is, of course, correct that the equity portion of AP&L's financing was necessarily reliant on MSU which owns all the common stock of AP&L. However, in no instance did MSU form a separate corporation to assist AP&L with financing, nor did any of the sister operating companies guarantee to use the power and to pay for the facility, as was done with Grand Gulf in Mississippi.

The above circumstances demonstrate that the Grand Gulf nuclear station was planned, licensed, and constructed as a system plant, intended to supply power not only in Mississippi but throughout the entire MSU system. It is, therefore, an anomaly to the regular planning and construction of generating facilities by the operating companies of the Middle South system. As such, the financial responsibility and production cost responsibility for Grand Gulf should be borne by all the operating companies. Accordingly, the arrangement entered into in January 1980 by the MSU board in adopting a plan that would totally eliminate AP&L responsibility for its appropriate portion of the Grand Gulf facility, is unjust, unreasonable, and unduly discriminatory. Implementation of the 1982 System Agreement that would result in AP&L evading responsibility for its portion of Grand Gulf through the proposed Unit Power Sales Agreement, must be rejected as unjust and unreasonable.

Moreover, it should be pointed out that the findings and conclusions here with regard to the Grand Gulf facility are consistent with the holding of the Presiding Judge in the proceeding involving the Unit Power Sales Agreement covering Grand Gulf, *Middle South Energy, Inc.*, 26 FERC ¶63,044 (1984). However, the underlying rationale herein is different since Grand Gulf is considered an exception to normal generation addition procedures on the Middle South system, whereas the justification for the holding in the Unit Power Sales Agreement case is that the Middle South system is a single integrated electric utility which basically justifies production cost equalization, *id.* at pp. 65,110-11, 65,119. In contrast, the ruling on Grand Gulf in this proceeding is based on the fact that the Grand Gulf nuclear facility itself is a system plant, and was planned, constructed and financed as a system plant, as opposed to other generation additions that were owned by the individual operating companies and were financed by those

companies in line with the historic pattern of generation additions on the Middle South system.

It is necessary, however, to implement this ruling by integrating the Grand Gulf cost responsibility findings with the operation of the 1982 System Agreement. In the Unit Power Sales Agreement case, set percentages were assigned to the four operating companies, with AP&L entitled to 36%, LP&L 14%, MP&L 33% and NOPSI 17% of Grand Gulf Unit I, *id.* at pp. 61,119-20. For the reasons stated in that decision, entitlement percentages for Grand Gulf Unit 2 were not designated, *id.* at p. 61,120. While the responsibility percentages prescribed in the Unit Power Sales Agreement proceeding are reasonable at the present time, it would appear that some further allowance should be made for shifting demand patterns in the jurisdictions so that the jurisdictions using the Grand Gulf power will be paying their fair share of the costs over the life of the unit. As a result, it is warranted to extend the holding in Unit Power Sales Agreement case and integrate Grand Gulf into the 1982 System Agreement by having each of the four operating companies pay for the production costs of the Grand Gulf facility based on the ratio that the individual operating company's total annual demand bears to the total annual system demand. This ratio can be calculated at the close of the calendar year and the responsibility for Grand Gulf costs can be set for the subsequent year based thereon. To integrate this into the 1982 System Agreement, each operating company's share of Grand Gulf can be treated as part of the company's Capability under Section 2.14 of Article II of the 1982 System Agreement, as an input in MW available under contract from a supplying source. As such, it will affect each company's Capability Responsibility and become part of the calculation of reserve equalization under Section 10.03 of Service Schedule MSS-1 of the 1982 System Agreement. In that manner, the Grand Gulf share will be taken into account in determining which operating company is long or short.

No radical changes are needed to the 1982 System Agreement nor would MSE have to become a party to that agreement, and the result reached for Grand Gulf will be just and reasonable, that is, each of the four operating companies will pay their fair share of the production costs of Grand gulf.

4. Summary

In summary, the MPSC proposal that the 1973 System Agreement be reinstated with Grand Gulf becoming a participation unit and MSE a party to the agreement, has been rejected. It would result in substantial inequity to LP&L and NOPSI by having them pay the heavy front end costs of Grand Gulf, while affording MP&L preferential treatment in this regard. The MPSC plan also fails to meet the goal of having each operating company acquire base load nuclear or coal-fired capacity.

Regarding the other proposals, the production costs equalization plans versus the 1982 System Agreement, it must be concluded for the reasons stated above, that the 1982 System Agreement is consistent with the historic pattern of operation and generation additions on the Middle South system. Under that pattern, an operating company builds a facility larger than its own needs and sells the excess under a reserve equalization procedure, to its sister companies until the building company grows into the unit. The equalization proposals are not consistent with this pattern and would cause a drastic restructuring of intercompany transactions and relationships. Nor do the present circumstances relating .to flattening demand and high capacity costs, especially for the two new nuclear plants, require that equalization be ordered, particularly in light of the substantial effect equalization would have on State ratemaking. Therefore, the 1982 System Agreement is, with one exception, being approved as just and reasonable, and the equalization proposals are being rejected.

There is, as shown above, one major deviation from the historic pattern and that involves the Grand Gulf nuclear facility. The record shows that Grand Gulf was planned, licensed and constructed as a system facility and it must be treated as such, with each of the four operating companies sharing an appropriate cost responsibility therefor. This, in effect, is a form of cost equalization for Grand Gulf. In this regard, each of the operating companies will bear cost responsibility for Grand Gulf based on the ratio that the company's annual demand bears to the annual demand of the system as a whole. This will be integrated into the 1982 System Agreement by being considered as part of each operating company's Capability. Moreover, this treatment of Grand Gulf will lessen the cost disparities reflected in the cost comparisons shown in Section VI E, *supra,* where revenue requirements differences and annual costs of electricity variances are set out for the various production cost allocation proposals. Although a precise calculation has not been made, the treatment herein of Grand Gulf should result in economic differences at about the midpoint of those shown for the 1982 System Agreement and the two equalization proposals. See MSS Exs. 19, 20, 21, 23, 59, 60, 61 and 63. The net effect is that Grand Gulf will be equalized but Waterford 3 will not be.

Overall, the results reached herein provide the most equitable resolution of the controversy over production cost allocation and will result in a just, reasonable, non-discriminatory and non-preferential pooling agreement for the Middle South system.

VII. Findings and Conclusions[2]

Based on the evidence of record and on the analyses, rulings and determinations made in this initial decision, the following findings and conclusions can be entered.

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[2] The findings and conclusions are meant to set out the essential rulings made in the initial decision. Any ambiguity or apparent incon-

1. The zone of reasonableness for the return on equity to apply to the 1982 System Agreement should range from 15% to 16% and the return on equity should be set toward the high end of the zone, because of current market conditions and the perceived risks relating to nuclear investment. As a result, a 15.75% return on equity is just and reasonable and is approved.

2. The proposals by CNO and LPSC regarding capitalization ratios and embedded costs of debt and preferred stock are rejected and the handling proposed by MSS for these matters is approved as just and reasonable.

3. The LPSC request for periodic review conditions to be attached to the 1982 System Agreement is rejected because the Commission's periodic audits will preclude recovery of improperly incurred costs and because of the safeguard that exists in Section 206 of the FPA, which permits institution of a hearing should an interested party or the Commission have reason to believe that improper costs are being allocated.

4. The proposed designation by MSS of Inter-Transmission Investment subject to equalization under Service Schedule MSS-2 of the 1982 System Agreement is just and reasonable and is approved.

5. The MSS classification of generating units is a reasonable categorization of base load and intermediate facilities and is approved.

6. The allocation by MSS of A & G expenses to pool transactions and its use of labor ratios to do so is just and reasonable and is approved.

7. The adder provisions in Service Schedule MSS-3 are just and reasonable and are approved.

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sistency that might arise therefrom should be resolved by referring to the full discussion of the particular area contained in the body of the initial decision.

8. The adder provisions in Service Schedule MSS-1 are just and reasonable and are approved.

9. The MPSC proposal that production cost allocation be accomplished through reinstatement of the 1973 System Agreement with MSE becoming a party thereto, is rejected as not being just and reasonable since it would produce inequitable and discriminatory results.

10. The adoption of any of the production cost equalization proposals is rejected because such proposals are not just and reasonable since they do not comport with the historic pattern of operations and generation additions on the Middle South system and since they would result in a substantial intrusion on State ratemaking authority and would be inconsistent with representations made to State commissions. Moreover, production cost equalization is not justified at this time on the grounds that current circumstances relating to an overabundance of reserves and the very substantial construction costs for new generating units require equalization.

11. Because the Grand Gulf nuclear facility was planned, licensed, and constructed as a system plant, it is an anomoly to the regular pattern of planning and constructing generating facilities on the Middle South system. In light of this, financial responsibility for Grand Gulf should be borne by all the operating companies. This financial responsibility for each operating company will be determined based on the ratio that an individual company's annual demand bears to the annual demand of the entire system. These ratios should be calculated at the close of each calendar year and each company's responsibility for Grand Gulf set for the subsequent year based thereon.

12. To integrate the Grand Gulf rulings into the 1982 System Agreement, each operating company's share of Grand Gulf shall be considered part of the company's Capability under Section 2.14 of Article II of the 1982 System

Agreement, as an input in MW available under contract from a supplying source.

VIII. Order

Based on the evidence of record, on the analyses, rulings and determinations made in this initial decision and on the findings and conclusions herein, it is ordered that the 1982 System Agreement be adopted as proposed by MSS with appropriate modifications thereof made to conform it to the rulings made in this decision on return on equity and on the Grand Gulf nuclear facility.

The action in this initial decision is subject to review by the Commission on appeal or on its own motion, as provided for in Rules 711 and 712 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§385.711 and 385.712.

APPENDIX E

CITED AS "26 FERC¶. . . ."

[¶63,044]

Middle South Energy, Inc., docket No. ER82-616-000

Initial Decision Concerning Sales of Power From the Grand Gulf Nuclear Generating Plant

(Issued February 3, 1984)

Ernst Liebman, Presiding Administrative Law Judge.

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Appearances

Elizabeth H. Ross for Missouri Public Service Commission

Hiram C. Eastland, Jr. and *Champ Terney* for Mississippi Public Service Commission

Richard M. Merriman, Robert S. Waters, *James K. Mitchell, Lisa H. Powell,* and *William D. Meriwether* for Middle South Energy, Inc.

Nathan Norton for Arkansas Public Service Commission

John L. Maxey and *Michael Raff* for Mississippi Legal Services Coalition

Frank Spencer and *Bill Allain* for the Mississippi Attorney General

Paul L. Zimmering, Michael R. Fontham, Marshall B. Brinkley, and *Bruce M. Louiselle* for Louisiana Public Service Commission

David N. Carne and *Peter Goldsmith* for Cities of Conway and West Memphis, Arkansas

Bernays Thomas Barclay, John B. O'Sullivan, and *Rigdon H. Boykin* for International Paper Company

Glen L. Ortman, Clinton A. Vince, and *Gregg D. Ottinger* for the City of New Orleans

Robert H. Wood, Jr. and *Linda Lipe Gleghorn* for the Arkansas Public Service Commission

Hubbard T. Saunders and *Bennett E. Smith* for the Mississippi Public Service Commission.

Roger W. Giles and *Garry S. Wann* for the Office of Attorney General, State of Arkansas

Earle H. O'Donnell and *Robert R. Morrow* for Occidental Chemical Corporation

Richard M. Troy for the State of Louisiana

Charles Reusch, Robert L. Woods, James E. Rogers, Michael Small, and *Maureen Thompson* for the Staff of the Federal Energy Regulatory Commission

I. Background

This case involves an agreement to sell electricity from a nuclear generating plant. The broad issue is whether a Unit Power Sales Agreement providing for the sale of the nuclear power is just, reasonable and not unduly discriminatory within the meaning of the Federal Power Act. 16 U.S.C. §824, *et. seq.* The Agreement provides for the sale by Middle South Energy, Inc., of capacity and energy from its Grand Gulf Nuclear Generating Station to three affiliated electric utilities in Mississippi and Louisiana.

While the parties to this proceeding have raised many issues concerning the Agreement, the main issue is which customers of the Middle South Utilities system will have to pay for and be entitled to receive Grand Gulf capacity and energy. This issue overrides all others in importance because of the large rate increases which will be necessary to pay for the nuclear power. Middle South proposes that all the Grand Gulf costs be paid by Middle South's customers in Mississippi and Louisiana. But some of the parties argue that Middle South's customers in Arkansas and Missouri should share some of the Grand Gulf costs.

The Unit Power Sales Agreement, dated June 10, 1982, is among Middle South Energy, Inc. ("MSE"), Louisiana Power & Light Company ("LP&L"), Mississippi Power & Light Company ("MP&L"), New Orleans Public Service, Inc. ("NOPSI") and Arkansas Power & Light Company ("AP&L"). The common stock of these companies is owned entirely by Middle South Utilities, Inc. ("MSU"), a registered holding company under the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79, *et seq.*

AP&L, LP&L, MP&L and NOPSI are electric utility operating companies of the Middle South system. These companies provide electric service at wholesale and retail in portions of the states of Arkansas, Louisiana, Mississippi and Missouri (Ex. 1, pp. 1-3). The planning, construction and operation of their generation and transmission facilities are coordinated and integrated. All capacity and energy on the Middle South system is centrally dispatched from the system's dispatch center at Pine Bluff, Arkansas (Tr. 347-348).

MSE was formed in 1974 to construct, finance and own generating capacity. At present MSE's only generating plant is the Grand Gulf Nuclear Electric Station now under construction near Port Gibson, Mississippi (Ex. 1, p. 3; Ex. 6, pp. 1-2, Ex. 23).

Grand Gulf originally was intended to be a two-unit nuclear-fueled generating station. Ninety percent of Grand Gulf is owned by MSE and 10 percent by the South Mississippi Electric Power Association (Ex. 6, p. 1). The Nuclear Regulatory Commission issued a low power testing license for Grand Gulf Unit No. 1 on June 16, 1982. At the time the testimony was received in this case, Unit No. 1 was scheduled to begin commercial operation in the fourth quarter of 1983 (Ex. 1, pp. 3-4; Ex. 61, p. 1). The small amount of construction on Unit No. 2 was suspended in 1979. The schedule for completion of Unit No. 2 and the cost of construction of that unit depend in part on the successful completion and operation of Unit No. 1 (Ex. 61, p. 1).

MSE proposes to sell all of the capacity and energy available to it from Grand Gulf to LP&L , MP&L and NOPSI pursuant to the Unit Power Sales Agreement (Ex. 6, p. 2; Ex. 7, p. 2). Under the Agreement no Grand Gulf capacity and energy would be sold to AP&L by MSE. The Agreement provides that each purchaser shall pay its proportionate share, as defined in the Agreement, of the total

cost of power from each unit. Most charges under the Agreement would be adjusted automatically from month to month. The adjustments would be based on changes in costs actually incurred by MSE. However, the recovery of certain costs, including the rate of return on common equity, the rate at which depreciation expense is accrued, and nuclear plant decommissioning expenses, would not be subject to change without a rate filing with the Federal Energy Regulatory Commission (Ex. 6, p. 3; Ex. 8).

Initially MSE proposed that its recovery of estimated spent nuclear fuel disposal costs would not be subject to automatic adjustment. However, as shown in the rebuttal testimony of E. Eugene Brown and Felix M. Killar, Jr., because of the passage of the Nuclear Waste Policy Act of 1982, it is appropriate to automatically adjust such expenses based on changes in charges imposed by the Department of Energy (Ex. 62, pp. 1-2; Ex. 63; Ex. 68; Ex. 69, Ex. 70). In *Pennsylvania Power and Light Co.*, 23 FERC ¶ 61,006, p. 61,019 (1983), the Commission ruled that the spent nuclear fuel disposal charge to be included in a cost-of-service formula rate for sale of energy from a nuclear power plant should be consistent with the Nuclear Waste Policy Act of 1982. During the hearing in this proceeding, the parties agreed that no issue remained with respect to the proper amount to be charged for, or rate treatment of, spent nuclear fuel disposal costs (Tr. 96-98).

On June 18, 1982, MSE tendered the Unit Power Sales Agreement for filing as an initial rate schedule with the Federal Energy Regulatory Commission. A notice of filing was issued by the Commission on June 30, 1982 (47 Fed. Reg. 29360). In response to that Notice, timely petitions to intervene were filed by the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Mississippi Public Service Commission, the Mississippi Attorney General, and the Mississippi Legal Services Coalition.

By order issued August 25, 1982, the Commission accepted for filing MSE's Unit Power Sales Agreement and a related Billing Format, found that the filing constituted a rate change rather than an initial rate filing, and suspended the rates which were to become effective, subject to refund, upon the initiation of service from Grand Gulf. 20 FERC ¶61,206 (1982). The Unit Power Sales Agreement was designated as MSE's Rate Schedule FERC No. 1, and the Billing Format was designated as Exhibit A to Rate Schedule No. 1. The Commission provided for a hearing pursuant to Sections 205 and 206 of the Federal Power Act and granted the petitions to intervene.

On September 24, 1982, MSE filed a request for rehearing of the Commission's August 25, 1982 order, and on October 20, 1982, the Commission granted rehearing for the purpose of further consideration.

On December 30, 1982, the Commission issued an order granting rehearing in part and clarifying its August 25 order with regard to proper tax normalization procedures to be reflected in MSE's final approved rates. 21 FERC ¶61,393 (1982).

On May 24, 1983, the Commission issued an order granting rehearing, clarifying its August 25, 1982, order and reinterpreting the Commission's statutory suspension authority. 23 FERC ¶61,277 (1983). The Commission found that MSE's Unit Power Sales Agreement was properly submitted as an initial rate, and the Commission determined that it had authority to suspend initial rates under Section 205 of the Federal Power Act. The Commission concluded that MSE's rates should be collected subject to refund. On June 9, 1983, MSE filed a Petition for Review of the Commission's Orders of August 25, 1982 and May 24, 1983 with the U.S. Court of Appeals for the District of Columbia Circuit. *Middle South Energy, Inc. v. F.E.R.C.*, CADC No. 83-1632. Thereafter, on June 23, 1983, MSE filed an Application for Rehearing of the May 24, 1983

Order. The Commission denied that application on August 1, 1983. 24 FERC ¶61,205.

Subsequent to the August 25, 1982 order, untimely petitions to intervene were filed by the Cities of Conway and West Memphis, Arkansas, the Missouri Public Service Commission, the City of New Orleans, Louisiana, the State of Louisiana, the State of Arkansas, Occidental Chemical Corporation, International Paper Company, the Cities of Benton, North Little Rock, Osceola, and Prescott, Arkansas, and the Farmers Electric Cooperative Corporation. These petitions were granted by the Presiding Administrative Law Judge (*see* orders issued October 12 and November 18, 1982 and January 25 and February 28, 1983).

On October 15, 1982, the Louisiana Public Service Commission, the Mississippi Public Service Commission, Mississippi and the Mississippi Legal Services Coalition filed a motion to consolidate this proceeding with Docket No. ER82-483-000. The motion was denied by the Chief Administrative Law Judge on November 12, 1982. 21 FERC ¶63,039, p. 65,186 (1982). A request that the order denying consolidation be referred to the Commission was denied by the Chief Administrative Law Judge on January 14, 1983. 22 FERC ¶63,015 (1983).

The hearing began on March 14, 1983, and concluded on May 12, 1983. The record consists of 2917 pages of transcript and 159 exhibits.

II. Issues

After discussions with all the parties and after considering pretrial briefs, the presiding administrative law judge issued orders defining and limiting the issues to the following questions (Tr. 248-251, 269, 582-583):

1. Is MSE's proposed allocation of the costs of power and energy and of power and energy available to MSE from Grand Gulf Unit Nos. 1 and 2 just, reasonable and not unduly discriminatory?

2. Should the Federal Energy Regulatory Commission decide the issue of the allocation of the costs of power and energy from Grand Gulf Unit No. 2 at this time?

3. Has good cause been shown for the use of an automatic adjustment clause in the Unit Power Sales Agreement?

4. Should the costs of Grand Gulf Unit No. 2 be included in the automatic adjustment clause of the Unit Power Sales Agreement?

5. What limits are appropriate on the discretion of MSE to include costs within the cost-of-service formula of the Unit Power Sales Agreement?

6. What is the appropriate rate of return on equity for MSE?

7. What is the appropriate method and life for determining the depreciation expense for MSE?

8. With respect to nuclear plant decommissioning expenses:

A. What is the appropriate amount for the total expense?

B. What is the appropriate annual amount to be included in MSE's cost-of-service?

C. Should the funds for decommissioning be accrued in an internal or external sinking fund?

9. What is the appropriate allowance for MSE's cash working capital?

10. Should MSE's cost-of-service include a provision for customer service and informational expenses and sales expenses?

11. Has MSE substantiated its claim that it has met the tax normalization requirements of the Economic Recovery Tax Act of 1981?

12. Should MSE's rate of return contain an incentive provision based upon the energy production of the Grand Gulf units?

13. Should MSE be required to refile its Unit Power Sales Agreement every five years under Section 205 of the Federal Power Act?

14. Should the tariff in the Unit Power Sales Agreement include a provision for the optional levelization of charges at the retail level?

15. Even if the automatic adjustment clause cost-of-service tariff is approved for MSE, should it be approved for amortization expenses and gains and losses from disposition of utility plant?

III. Discussion

A. Allocation of Grand Gulf Unit No. 1

1. The Issue

The main issue in the case is whether MSE's proposed allocation of the costs of power and energy and of power and energy available to MSE from Grand Gulf Unit Nos. 1 and 2 is just, reasonable and not unduly discriminatory (Tr. 251).

Paragraph 1.2 of the Unit Power Sales Agreement, which MSE is asking this Commission to approve, contains the following provision (Ex. 7, p. 2):

1.2 The Purchasers shall, subject to the terms and conditions of this Agreement, be entitled to receive all of the Power which shall be available to MSE at the Project in accordance with their respective Entitlement Percentages. The entitlement Percentages are as follows:

	Entitlement Percentages	
	Unit No. 1	*Unit No. 2*
LP&L	38.57%	26.23%
MP&L....................	31.63%	43.97%
NOPSI	29.80%	29.80%
	100.00%	100.00%

The Agreement expresses the entitlements in terms of percentages because at the time the Agreement was to be signed it was not known how many megawatts of capacity from Grand Gulf would be available to LP&L, MP&L and NOPSI. As explained by Mr. Lupberger, South Mississippi Electric Power Association had acquired a 10% interest or 125 megawatts of capacity (1250 megawatts x 10% = 125 megawatts) in each of the two Grand Gulf Units; in addition, MSE was negotiating with the Municipal Energy Agency of Mississippi (MEAM) to sell it a 2.48% or 31 megawatt interest (1250 megawatts x 2.48% = 31 megawatts). Thus the total sale would be 156 megawatts of the 1250 megawatts of power from each Grand Gulf Unit (Ex. 1, p. 13).

Assuming the sale of the 156 megawatts and the entitlement percentages stated in the Agreement, the allocations of power from Grand Gulf pursuant to the Agreement would be as follows:

	Unit 1 (MW)	*Unit 2 (MW)*
AP&L	0	0
LP&L	422	287
MP&L....................	346	481
NOPSI	326	326
Co-Owners	156	156
	1250	1250

The next section of this Initial Decision holds that the

issue of allocating Grand Gulf Unit No. 2 should not be decided at this time. Therefore, the following discussion deals solely with the allocation of Grand Gulf Unit No. 1. With respect to Unit No. 1, Staff and MSE support the allocation percentages incorporated in the Unit Power Sales Agreement. However, the Louisiana Public Service Commission, the City of New Orleans, and the Mississippi Public Service Commission each have proposed alternative allocation schemes. The following table shows a comparison of the allocations of power from Grand Gulf Unit No. 1 proposed by MSE in the Unit Power Sales Agreement, by the Louisiana Public Service Commission (LPSC), and by New Orleans:

	Unit Power Sales Agreement	*LPSC*	*New Orleans*
AP&L	0	36%	33.11%
LP&L	38.57%	14%	42.74%
MP&L	31.63%	33%	15.72%
NOPSI	29.80%	17%	8.43%

(MSE Initial Brief, p. 3; LPSC Initial Brief, p. 50; New Orleans Initial Brief, p. 26). In addition to these proposals, the Mississippi Public Service Commission supports a scheme under which the allocations would vary.

The other parties to this proceeding have aligned themselves with one or another of these proposals. Because the costs of power from Grand Gulf are perceived to be much higher than the costs of power from other sources on the MSU system, it is not surprising that each of these parties supports an allocation of power which results in the lowest allocation to the MSU operating company or companies in which the party is interested, especially during the early years of operation of Grand Gulf when the costs of Grand Gulf are higher than in later years. Thus Arkansas, the Arkansas Public Service Commission, and the Cities of Conway and West Memphis, Arkansas (and in effect In-

ternational Paper Company) support the allocation set forth in the Unit Power Sales Agreement which allocates no Grand Gulf power to AP&L; LPSC and Occidental Chemical Corporation support the LPSC method, which allocates only 14 percent of Grand Gulf power to LP&L; and New Orleans supports its own allocation, which allocates only 8.43 percent of Grand Gulf power to it. The Mississippi Attorney General prefers the MPSC variable allocation method, but also conditionally supports the fixed allocation proposal of New Orleans.

Before discussing these allocation proposals in detail, it will be helpful to set out some background of the Middle South system, the Middle South System Agreement, Middle South's generation expansion, and the Grand Gulf Project.

2. The Middle South System

The Middle South system consists of a parent holding company (MSU) and various subsidiary companies wholly owned by MSU. These subsidiaries include four operating companies (AP&L, LP&L, MP&L, and NOPSI), a single asset generating company (MSE), and a corporate services company, Middle South Services, Inc. ("MSS"). Although subdivided into separate corporate entities, the Middle South system has common officers who plan and operate Middle South system as a coordinated, fully integrated electrical system (Ex. 1, pp. 2-3; Tr. 347-48).

Mr. Lupberger, an officer of MSU, MSE, and MSS and the highest ranking Middle South Official to testify in this case, stated that the "generation, transmission and distribution facilities of AP&L, LP&L, MP&L and NOPSI are integrated to form the Middle South System." (Ex. 1, p. 2.) In explaining his use of the term "integrated" on cross examination, Mr. Lupberger stated that "the Middle South System is operated as though it were one electrical system under one ownership." (Tr. 347.) "In all candor," he added "[it] probably could not be separated or pulled

apart without detrimental effects to the customer economically." (Id.)

Mr. Lupberger further testified that planning, construction and operation of major generation facilities are performed by Middle South as a single system on a coordinated basis. He stated that the planning for all new generating units, such as Grand Gulf, is done on a system basis by the Middle South System Operating Committee. The System Operating Committee consists of one representative from each of the operating companies and two representatives from MSS. The operating company representatives, who are designated by their chief executive officers, collectively share 80% of the voting power on the Committee in proportion to their companies' respective "responsibility ratios" (a term which will be explained in a few moments). The two MSS representatives share the remaining 20% of the voting power (Tr. 348, 361, 395-6,730-4).

Mr. Lupberger's testimony was confirmed by two other MSE witnesses, Mr. Trumps and Mr. Stampley. Mr. Trumps is the Director of the System Planning and Forecasting Department at MSS, a wholly owned service company subsidiary of MSU. MSS provides accounting, engineering and other administrative services to the four operating companies (Ex. 1, p. 2). MSS is responsible, *inter alia,* for long-range generation expansion planning for Middle South. Mr. Trumps stated that "we don't add capacity, of course, for individual companies." (Tr. 1294.) He explained that generation additions are planned on a system-wide basis, including decisions as to the type, size, location, and timing of construction of units. In particular, he noted that the timing of generation unit additions takes into account overall system reserve capabilities. Mr. Trumps also testified that such coordinated system planning is intended to provide the best service to the system as a whole and to the public (Tr. 967-72; 911-17; 947).

Mr. Stampley, a Senior Vice President for MP&L and a former member of the Operating Committee, agreed that generation additions were planned by the System Operating Committee to serve the needs of the system and of the individual operating companies. He also agreed that decisions on generation additions were made on the basis of the system as a whole, including site selection to achieve locational economies (such as locating units due to access of fuel supply or available water supply), sizing units to achieve economies of scale, and timing construction of units to achieve desirable levels of system reserves (Ex. 46, pp. 4, 5, 7; Ex. 47, pp. 4, 10, 34). He stated that the operating companies jointly plan on a system basis for the construction and operation of major facilities to best meet the combined loads of all the companies and to provide the best level of service to the public. He also stated that the ultimate decision on the addition of new generating plant is made jointly by the chief executive officers of the operating companies, relying upon the recommendation of the System Operating Committee (Tr. 739-42, 746, 756, 780-6).

3. The Middle South System Agreement

The MSU system planning approach caused certain MSU operating companies to be short of adequate generating capability for long periods, while others possessed excess capacity. For example, the load of AP&L exceeded its capability in all but one year of the decade of the 1970's (Tr. 945). Arkansas-Missouri Power Co., which has since merged with AP&L, had capability sufficient to serve only 12 percent of its peak load in 1974; it was capable of serving 59 percent of its peak load in 1980 (Tr. 946). The power and energy to remedy these inadequacies came from the other MSU companies, which constructed capacity in excess of their individual needs to take advantage of natural economies available in their jurisdictions, such as a ready supply of cheap natural gas (Tr. 947-49). The same

situation existed in the 1960's, when AP&L purchased large quantities of power and energy from LP&L (Tr. 949).

In 1973 the operating subsidiaries of the Middle South system executed an agreement for the purpose, among others, of achieving an appropriate sharing of costs because of the imbalances in reserves due to the earlier system approach in adding generating capability.

The 1973 MSU System Agreement recognized that "economies of scale require that the planning, construction, and operation of the bulk power supply and related facilities of the [Middle South Operating] Companies to be on the basis of a single system. . . ." *See* Item "B" by reference, *Middle South Services, Inc.*, Docket No. ER79-277, and Tr. 388, 780, 912.

Paragraph 3.01 of the 1973 System Agreement sets forth its purpose (13 FERC ¶63,032, p. 65,097):

> . . . to provide the contractual basis for the continued planning, construction, and operation of the electric generation, transmission and other facilities of the Companies . . . and to provide a basis for equalizing among the Companies any imbalance of costs associated with the construction, ownership and operation of such facilities as are used for the mutual benefit of all the Companies.

Under the 1973 System Agreement, each company's relative responsibility for its proportionate ownership of total system generation was determined by its relative load responsibility. The determination of relative load responsibility was based upon a 4 non-coincident peak methodology (Ex. 104, p. 1). For example, if Operating Company A's load was 30% of the total system load, its responsibility for total system capacity would also be 30%. If total system capacity were 10,000 megawatts, Operating Company A's "capability responsibility" would be 3,000 megawatts. If its individually owned or purchased capacity were

greater than 3,000 megawatts, it would be considered "long" and be entitled to receive "equalization" payments from companies which were "short." Conversely, if Company A had less than 3,000 megawatts of capacity, it would be considered "short" and be required to make "equalization" payments to companies which were "long" (*See* Tr. 918-20; 16 FERC ¶ 61,101, p.61,217).

In determining capability responsibility under the 1973 System Agreement, each kilowatt of capacity is given equal weight, with no differentiation relating to the cost per kilowatt of capacity (Tr. 824). One should also note that the terms "long" and "short" reflect a company's capacity and load relative to the system's capacity and load. Thus the fact that a company is "short" under the System Agreement does not necessarily mean that, standing along, it lacks adequate generating capacity to meet its customers' requirements, but only that it has less capacity than its proportionate system load responsibility.

For example, assume (a) total system load was 7,500 megawatts, (b) total system capacity was 10,000 megawatts, (c) Company A's load responsibility was 2250 megawatts (30% of 7,500 megawatts), (d) Company A's capacity was 2,700 megawatts, and (e) its peak load was 2350 megawatts, then its capacity responsibility would be 3,000 megawatts (30% of 10,000 megawatts), and it would be "short" because its capacity is only 2,700 megawatts, even though its capacity exceeds its peak load: 2,700 megawatts versus 2,350 megawatts.

Prior to 1973, the capacity equalization payments made by a "short" company to a "long" company under the System Agreement were based upon a fixed dollar amount per kilowatt. In 1973, the System Agreement was amended to provide for capacity equalization payments based upon a so-called "participation unit" concept. Under this approach, the capacity equalization payments were based upon the ownership costs of the latest unit constructed by

the "long" company, with the "short" company thereby entitled to a proportionate share of that "participation unit," including a proportionate share of energy generated by that unit. For example (assuming a two company "system"), if (a) Operating Company A were "long" and its latest unit had 1,000 megawatts of capacity, and (b) Operating Company B were "short" by 500 megawatts, then (i) Company B would make equalization payments for 500 megawatts to Company A based upon the costs of Company A's latest unit and (ii) Company B would be entitled to 50% of the power and energy from that unit. Because generation system additions were planned and constructed to meet Middle South's system load, the "participation unit" concept provided a means for sharing the costs of a new unit when that unit was too large for the needs of the company building the unit.

Mr. Stampley explained that the costs per kilowatt of installed capacity of the various operating companies of the Middle South system in the early years of operation were roughly equal, and thus equalizing kilowatts also generally equalized costs. Mr. Stampley also noted that the system was ". . . growing such that new units were needed on a frequent basis, and it tended to equalize itself because companies would alternately install new units." (Tr. 803). Even when some disparities developed in the cost per kilowatt of capacity being added by the operating companies, total costs of generation (in terms of cents per kilowatt-hour) from these new units were roughly equivalent due to the fuel savings associated with the higher cost capacity (Tr. 803).

Because of the rotation of responsibility for adding new capacity which would gradually increase in cost per kilowatt but would be roughly equivalent in total cost per kilowatt-hour, the effect of the operation of the 1973 System Agreement was to tend to equalize system generation costs among the operating companies despite the fact that

capability equalization payments were calculated on the basis of equalizing kilowatts and not equalizing dollars. *See* 16 FERC ¶61,101, p. 61,221.

The proportionate allocation of costs among the operating companies was disrupted when large cost escalations occurred on two new nuclear units. The Waterford 3 Unit, which was assigned for construction to LP&L, escalated in cost to a projected $2.4 billion (Tr. 905-907). Grand Gulf Unit No. 1, which was originally assigned for construction to MP&L, escalated to a projected cost of $2.5 billion (Tr. 340). The financing pressures associated with the unit were so great that MSU was forced to relieve MP&L of the responsibility to finance the Grand Gulf generator. MSE was formed by MSU to finance the unit, although MP&L is constructing and will operate it (Tr. 350, 414).

In light of the escalation of costs of the Waterford 3 and Grand Gulf units, the concept of kilowatt-for-kilowatt capability equalization under the 1973 System Agreement will no longer achieve cost equalization. The kilowatts gained by the addition of these units would be "equalized" by far cheaper kilowatts in other jurisdictions. The kilowatt-for-kilowatt concept, which previously achieved cost equalization, would now result in large disparities of cost allocation.

In 1982, Middle South Services, Inc., made a filing with FERC in Docket No. ER82-483-000. In that filing MSS proposed a new method for the MSU system of providing for capability equalization. The filing superseded the 1973 System Agreement. Under the new MSS proposal the embedded investment in "intermediate" generation of a long company is used to calculate the payments rather than investment in a "participation" unit.

4. Middle South's Generation Expansion

In the 1960's and 1970's, Middle South's generation facilities, planned on a system-wide basis, were located

mainly in Louisiana and Mississippi because large units, which exceeded the demands in those jurisdictions, were constructed to achieve economies of scale and to take advantage of the available fuel supply, particularly low cost natural gas in Louisiana (Tr. 813, 817-20, 912, 943). As stated by Mr. Lupberger (Ex. 1, p. 4):

> [T]he construction of new generating units needed to meet the growing demands on the Middle South System was coordinated among the individual operating companies on the basis of each company's need for new capacity, and the optimal location of new capacity on the system.

As a result, in the 1960's, AP&L made substantial purchases of energy from LP&L (Tr. 949-50). This trend continued throughout the decade of the 1970's. During that time period, AP&L's peak load consistently exceeded its own generating capability. For example, in 1974, AP&L's capability, standing alone, was only 78% of its peak load, while Ark-Mo's capability was only 12% of its peak load (Tr. 814-5, 944-6). From the time the 1973 System Agreement became effective in August 1973 until March 1980, AP&L was "short" and purchased capacity under the "participation unit" concept from the other operating companies (Tr. 1995). By contrast, throughout the 1970's, LP&L's own generating capability consistently exceeded its peak load (Tr. 816, 947), a circumstance which also was generally true for MP&L and NOPSI during this period (Tr. 816-7).

The oil and gas units which went into service on the Middle South system prior to 1970 were relatively inexpensive (less than $100 per kilowatt) (Ex. 98; Tr. 1332-33). Moreover, each of the operating companies added major oil- and gas-fired units in the late 1960's and early 1970's (Ex. 98).

While the MSU operating companies were adding these oil- and gas-fired units, Middle South was planning a major

expansion of its generation capacity which for the first time would include nuclear and coal units. In 1974-75, three major new units were added. In December 1974, AP&L brought on line the Middle South system's first nuclear plant, the 836 megawatt Arkansas Nuclear One (ANO) Unit 1. Soon thereafter, LP&L added 822 megawatts of oil-fired capacity in Waterford Units 1 and 2, and MP&L added 760 megawatts of oil-fired capacity in Andrus Unit 1. Although the capacity cost of ANO 1, the nuclear unit, was $276 per kilowatt, which was almost double that of the oil-fired Waterford and Andrus units ($150 per kilowatt), there was not a significant difference in the initial "busbar" or total generation costs (about 3¢ per kilowatt-hour) of those units in 1975. This fact was due to the lower fuel costs associated with the nuclear unit (Tr. 936, 1286-87). Although the initial generation costs were roughly equal when those plants came on line, it was at the same time apparent that AP&L would be substantially better off with the ANO nuclear unit over its life than LP&L and MP&L would be with the oil-fired units because of the cheap energy costs associated with the nuclear unit (Tr. 1287, 2199-2200, 2249-52, 2262-3).

AP&L was assigned to build the first nuclear unit on the Middle South system for a number of reasons. In the late 1960's and early 1970's, AP&L began to lose its long-term gas contracts. In addition, for some time, AP&L had been (and would continue to be) "short" both in terms of the 1973 System Agreement and in terms of its capacity compared to its own load requirements. Moreover, the system still had a favorable gas and oil fuel supply in Louisiana and Mississippi. Given that Middle South had seen the need to move the system as a whole away from oil and gas generation, it was logical from a system perspective to have AP&L build the first unit which was not fired by oil or gas (Tr. 369, 948).

After the 1974-75 plant additions, no new major generating facilities went into operation until the 1980's. How-

ever, significant construction activity was going forward. LP&L had begun construction of Waterford 3, a nuclear unit, in the early 1970's followed by MSE initiating construction of Grand Gulf in September 1974 (Ex. 1, pp. 4-5). AP&L was continuing construction of ANO 2 and of several coal-fired units.

In 1980, AP&L put into operation its second (858 megawatts) nuclear unit (ANO Unit 2) and, in 1980 and 1981, respectively, two coal-fired units at White Bluff totaling 930 megawatts (Ex. 98; Tr. 896-7). These units are jointly owned by AP&L with certain Arkansas municipal and cooperative electric utilities (Ex. 19, p. 4). AP&L's share of each White Bluff unit was 465 megawatts. In 1982, the first coal-fired unit at Independence went into operation with Middle South's 468 megawatts share of the unit jointly owned by AP&L (260 megawatts) and MP&L (208 megawatts) (Tr. 762; Ex. 84). This unit is also jointly owned by certain Arkansas municipal and cooperative electric utilities (Ex. 84; Tr. 763) Each of these units—ANO 2, White Bluff 1 & 2, and Independence 1—went into operation at an initial cost of 4 to 5 cents per kilowatt-hour (Exh. 125; Tr. 1305, 1337).

Over the same time period that AP&L and, to a limited extent, MP&L were financing and constructing these units, LP&L was financing and constructing the Waterford 3 nuclear unit (1104 megawatts), and MSE was constructing Grand Gulf Unit No. 1 (1125 megawatts for MSE's share). However, the construction of the Waterford and Grand Gulf plants was substantially delayed (Tr. 843-5). As a result, the costs of these nuclear units grew dramatically.

The projected cost of LP&L's Waterford 3 is about $2.1 billion for 1104 megawatts, or about $1900 per kilowatt. This figure, however, does not take into account that LP&L's ratepayers have been paying a return to LP&L for construction work in progress (CWIP) included in rate base. Since Grand Gulf has been constructed without any

current return for CWIP (which has been capitalized), an adjustment must be made to Waterford 3's projected cost to reflect the CWIP return in order to compare the total costs of Grand Gulf 1 and Waterford 3 on an equivalent basis. If this is done, the cost for Waterford 3 would be about $2.4 billion or, like Grand Gulf, approximately $2200 per kilowatt (Tr. 463-4, 800, 907-908, 2241-42). Waterford 3 and Grand Gulf Unit No. 1 are expected to be on line by early 1984 at a total cost of over $5 billion.

Middle South does not project any other major plant additions except for the second coal-fired Independence unit, which will also be jointly owned by AP&L (260 megawatts) and MP&L (280 megawatts). This unit is expected to operate at less than $500 per kilowatt (Tr. 1341). In the early 1990's, LP&L is projected to bring into operation two 800 megawatt coal-fired units at Wilton, at a currently projected cost of $1,200 per kilowatt (Ex. 19, p. 4; Ex. 168, p. 2; Tr. 1340-41). NOPSI may own jointly with LP&L 10% of each unit, or a total of 160 megawatts (Tr. 910).

5. The Grand Gulf Project

The Grand Gulf project was initiated by Middle South in the early 1970's to meet the then projected Middle South System demand by the end of that decade. The project was planned by Middle South to meet system load and, in particular, the load of MP&L (Ex. 46, pp. 2, 5, 7-8, 11, 13). Mr. Lupburger stated that initially the "driving force" behind construction of Grand Gulf Unit No. 1 was the need for additional capacity to meet system load requirements (Tr. 366). This was confirmed by Mr. Stampley (Tr. 1043), who also noted that this "has been true of every unit that we have ever built on the Middle South system." (Tr. 756.)

In the 1970's with the reduced load growth forecasts on the Middle South system, it became evident that Middle South no longer needed the capacity which would be available from Grand Gulf to meet forecasted system demand.

However, based on its projections for the cost of Grand Gulf and the increasing price of oil, Middle South anticipated that, even though it would have excess system capacity with the addition of Grand Gulf, the average overall cost per kilowatt-hour of electricity would be less than it would be if the system continued to rely upon oil- and gas-fired generation.

When Grand Gulf was originally planned, it was anticipated that MP&L would be responsible for financing and constructing Grand Gulf Unit No. 1 and that NOPSI would be responsible for financing and constructing Grand Gulf Unit No. 2 (Ex. 19, p. 4; Tr. 350-1, 741-2). With AP&L responsible for financing and constructing the ANO plant and LP&L responsible for financing and constructing Waterford Unit No. 3, each of the system operating companies would have been responsible for the financing and construction of a major nuclear generating plant. However, for a variety of reasons, this initial plan was not carried out. In the early 1970's, it was determined that the site near New Orleans for Grand Gulf Unit No. 2 was unsuitable for construction of a nuclear plant and that it would be more economical to construct both Grand Gulf units at a common site in Mississippi (Ex. 19, p. 4; Tr. 743-4, 1163). Thus responsibility for construction of both Grand Gulf units shifted to MP&L because the plant was to be physically located in its service territory (Tr. 744-5).

Soon thereafter it was determined that MP&L did not have the individual financial capability to finance construction of the first Grand Gulf unit. As a result, in 1974 MSE was established to facilitate the financing of Grand Gulf, and MSE acquired from MP&L all of MP&L's right, title and interest in the Grand Gulf project (Ex. 1, pp. 3-5; Tr. 337, 398, 413, 1163). The formation of MSE was a system decision and the financing of Grand Gulf construction became a system undertaking (Ex. 1, pp. 4-9; Tr. 350). To obtain a construction permit from the Atomic Energy

Commission and initial construction financing, all four Middle South operating companies, including AP&L entered into an Availability Agreement (June 21, 1974) with MSE which required each company to put their credit support behind the Grand Gulf project (Ex. 1, pp. 7-9, 15; Tr. 353-8). All four operating companies, including AP&L, are still financially liable for Grand Gulf costs in proportion to the specific percentages set forth in the Second Amendment to the Availability Agreement (June 15, 1981) (Ex. 1, p. 15).

When MSE was formed and construction of Grand Gulf began in 1974, no firm decision had been made by the Middle South system on the allocation of Grand Gulf power and energy. However, it was anticipated that MSE would become a party to the 1973 System Agreement and that the power available from Grand Gulf would be allocated among the operating companies under the terms of that Agreement (Ex. 2, p. 4; Ex. 75, p. 2; Ex. 79, pp. 5-6; Ex. 104, p. 2; Tr. 747, 872 1084-5). MSU system projections made in 1981, which were incorporated into the Second Amendment to the Availability Agreement, showed that under this approach the operating companies would have been responsible for Grand Gulf costs as follows: AP&L—17.1%; LP&L—26.9%; MP&L—31.3%; NOPSI—24.7% (Ex. 1, p. 15-17).

With the delay in the construction of the plant, the decision on the allocation of Grand Gulf was deferred. From 1977 to 1979 the MSU System Operating Committee conducted various analyses of the allocation issue (Tr. 878-9). At meetings on September 6 and 7, 1979, the Operating Committee recommended adoption of an allocation of Grand Gulf designated as "Plan 4A." However, the Operating Committee's recommendation of this plan was not unanimous. Mr. Jack Davey, LP&L's representative on the Operating Committee, voted against it (Ex. 101, p. 2).

Under Plan 4A, there would have been fixed allocations of Grand Gulf capacity among the operating companies as follows (Ex. 101, p. 6; Tr. 827-8, 1108):

	%	*MW*
AP&L	11.11	125
LP&L	13.51	152
MP&L	49.60	558
NOPSI	25.78	290
	100	1125

Moreover, under Plan 4A each company's respective share of the Grand Gulf capacity was to be subject to equalization as a "participation unit" under the 1973 System Agreement. This plan would have required an amendment to the 1973 System Agreement because otherwise all Grand Gulf capacity would be purchased capacity (from MSE) and, therefore, under the 1973 System Agreement would not have been subject to equalization as a "participation unit" (Ex. 20, p. 4).

Thus, under Plan 4A, each company's actual responsibility for Grand Gulf (as opposed to its fixed allocation) would vary from time to time depending on the degree to which it was "short" or "long" under the 1973 System Agreement. Under the load and capacity forecasts then being made, this plan would have resulted in all of MP&L's 558 megawatt share of Grand Gulf being treated as a "participation unit" and the responsibility for this capacity would have shifted to LP&L and NOPSI at least into the 1990's.

On November 20, 1979, the MSU Board of Directors tentatively approved Plan 4A, with LP&L's representative absent (Tr. 881-2, 1420). Subsequently, on January 15, 1980, the MSU Board approved a different allocation plan, which is the one being proposed by Middle South in this proceeding (Tr. 876, 878, 1415). The chain of events which led to the revised allocation plan approved in January 1980

by the MSU Board is not entirely clear in this record. However, it is clear that the MSU System Operating Committee never recommended nor endorsed the allocation plan adopted in January 1980 (Tr. 925, 1421).

A Memorandum of Understanding was signed by each of the chief executive officers of the operating companies in July 1980 (Ex. 83). Subsequently, in August 1980, the Boards of Directors of each of the operating companies approved the allocation plan for Grand Gulf. This allocation plan was eventually set forth in the Reallocation Agreement which was executed in July 1981 (Ex. 20; Tr. 1059).

The result of this allocation was the assignment of fixed allocations of Grand Gulf capacity and cost responsibility to LP&L, MP&L, and NOPSI with no allocation to AP&L; in addition, the Grand Gulf capacity was not made subject to "equalization" as a "participation unit" under the 1973 System Agreement.

Middle South's initial projections for the costs and benefits to be achieved from the Grand Gulf project have not been fulfilled. Grand Gulf was originally projected to come on line at a cost of approximately $500 per kilowatt, which was approximately the cost of AP&L's ANO units (Tr. 337-40). However, the costs of the project increased dramatically, in part because of regulatory delays and additional construction requirements (Tr. 843-5). Coupled with the spiralling inflation and increasing financing costs during the 1970's (*Id.*), Grand Gulf evolved from a projected total cost of $1.2 billion for *both* units to $2.8 billion for Unit No. 1 *alone* (Tr. 800). For the project as a whole, total costs are projected to exceed original cost estimates by some $4 billion or 400% (Tr. 3394-41). Thus Grand Gulf Unit No. 1 will come on line at a cost per kilowatt (as well as a cost per kilowatt-hour) three to four times greater than the cost of any existing unit on the Middle South system.

Over the life of the plant, MSE predicts that Grand Gulf may still produce net benefits for the Middle South system because Grand Gulf fuel costs are expected to be low and relatively stable. MSE's witness admits, however, that there is a substantial possibility Grand Gulf will turn out to be uneconomical in terms of its ultimate costs to ratepayers compared to alternate sources of generation. MSE's witness Perl, using favorable assumptions as to future oil prices and capacity factors, showed that it is equally probable that Grand Gulf Unit No. 1 will be more expensive than alternatives (Ex. 89, pp. 5-6). He conceded that "plausible" changes in the underlying assumptions can render the unit extremely uneconomical (*Id.* p. 7). Indeed, if the status quo prevails (*i.e.*, if there is no increase in the price of oil in real terms and the cost of money remains constant), Grand Gulf Unit No. 1 will likely cost more over its life than available alternatives (*Id.*, p. 8).

It is significant to note that oil prices have fallen since Dr. Perl first submitted his testimony and, as conceded by Dr. Perl, are likely to be far lower in 1984 than he predicted (Tr. 1541-9). Moreover, Middle South's rate of return witness, Dr. Dietz, testified that interest rates were likely to go up by 1984, contrary to Dr. Perl's assumption on this subject (Tr. 1541, 1813, 1816, 1818). It is clear that even under Dr. Perl's optimistic assumptions, the net cost of Grand Gulf through 1992 compared to existing alternative generation on the Middle South system will be a net ratepayer detriment of some $3 billion. Thus, between now and 1993 the total amount which ratepayers will incur for Grand Gulf power, based on Middle South's figures, will be $3 billion more than if the power were generated from existing units. While the "crossover" point (the time when Middle South predicts Grand Gulf power will begin costing less than other alternatives) is 1993, the "make whole" point (the time at which ratepayers will have recouped past excess payments) will not occur until the 21st century (Tr. 1580-83).

The question thus arises whether the allocation proposed by MSE for Grand Gulf is just, reasonable and not unduly discriminatory.

6. Discussion

Under the allocation scheme in MSE's Unit Power Sales Agreement, AP&L is given no entitlement to Grand Gulf Power. The parties opposing MSE's allocation proposal seek to have an entitlement of some portion of Grand Gulf power shifted to AP&L, thus reducing the entitlements of MP&L, LP&L & NOPSI.

The arguments of LPSC and Occidental Chemical Corporation, opposing MSE's entitlement scheme, may be summarized as follows. Middle South plans, constructs, finances and operates its generation plants on a systemwide basis. The decisions as the type, size, location and timing of generation plant additions are dictated by what is in the interest of the Middle South system as a whole. With respect to generation plant, there is one system, not four separate systems, even though each MSU system plant addition is financed by an individual MSU subsidiary company which assumes construction and ownership responsibility for that plant. In the case of Grand Gulf, MSE was simply used as a vehicle to permit joint financing and joint ownership responsibility for the Grand Gulf unit, built for system needs. Because generation is installed in the system to serve system needs, not individual company needs, a mechanism must be devised to insure that the financial burden of new generation is equitably shared among the operating companies.

The MSE allocation proposal, argues LPSC and Occidental, departs from the historic system goal of attempting to achieve cost equalization to ratepayers in the various jurisdictions served by the MSE system, because the proposal takes no account of the enormous investment costs associated with the recent nuclear units. By attempting to allocate its high cost nuclear capability among only three

companies, while permitting the customers of AP&L to enjoy the benefits of low cost nuclear and coal units, MSE's proposal would exacerbate rate differences that already have developed. Rates in Louisiana and Mississippi will rise dramatically under MSE's allocation plan.

A retail rate increase of more than $700 million has been requested by LP&L, while an increase of $250 million has been sought by NOPSI (Tr. 415). These rate increase requests attempt to "levelize" the costs of the nuclear generation, *i.e.*, some of the initial high costs of the nuclear generation are deferred for collection in rates in later years. Even if potential fuel savings are counted and the rates for Grand Gulf were "levelized" at the retail level, the rate cases request revenue increases of 30 percent for LP&L and 35 percent for NOPSI (Tr. 477, 479). Without levelization, the requests for rate increases would exceed 50 percent of 1982 revenues (Tr. 2245-47).

As stated by Mr. Lupberger, the "Arkansas customer is very fortunate" (Tr. 461). The system decided that the first nuclear units should be constructed by AP&L because it was the most economical option for the MSU system as a whole to have AP&L construct the plants at that time (Tr. 462). LP&L could have been assigned the responsibility by the Middle South system for constructing the first nuclear units; however, it had favorable gas contracts which were providing inexpensive generation at that time to the Middle South system. By the time it was LP&L's turn to build nuclear capacity, the facts and circumstances for nuclear plant construction had changed dramatically due to what MSE witnesses Lupberger, Stampley, Trumps, and Perl characterized as a "quirk of timing" (Tr. 462, 812,940, 1800).

The huge rate increases which would be imposed on some customers, while others enjoy the benefits of low cost generation, cannot be justified, argue LPSC and Occidental, by attributing the discrimination to the "quirk of

timing." MSE's proposed allocation perpetuates, rather than rectifies, the discrimination caused by the timing of the units to the serious detriment of Louisiana and Mississippi ratepayers, who will pay four times more for nuclear capacity than Arkansas ratepayers and substantially more in overall retail rates. The result is an unjust, unreasonable and unduly discriminatory allocation of costs among the operating companies and the localities and ratepayers served by Middle South.

LPSC and Occidental Chemical Corporation propose to end this discrimination by allocating Grand Gulf in such a way that the costs of all nuclear capacity on the MSU system would be spread among all the MSU operating companies roughly proportionate to each company's relative share of system demand. (Occidental Initial Brief, pp. 46-47, LPSC Initial Brief, pp. 24, *et seq.*) Such an allocation scheme would be consistent, they argue, with FERC's strong preference for rolled-in pricing of system costs on an integrated electric system. *Public Service Company of Indiana,* Opinion No. 783, 56 FPC 3003, 3035 (1976), *aff'd in relevant part, 575* F.2d 1204 (*7th* Cir. 1978); *Missouri Utilities Company,* Opinion No. 82, 10 FERC ¶61,297, p. 61,599 (March 28, 1980); *Nevada Power Company,* 3 FERC ¶61,273, p. 61,728 (June 27, 1978). In addition, LPSC and Occidental contend that their allocation scheme would minimize the discrimination between current and future ratepayers on the MSU system. This discrimination occurs because for the near future Grand Gulf is a detriment to ratepayers when compared to available generation alternatives over the next ten years; only at some future time might the investment in Grand Gulf result in lower rates for future customers.

The City of New Orleans makes arguments against MSE's proposal which are similar to the arguments of LPSC and Occidental. In addition New Orleans argues that MSE's justification for MSE's allocation scheme—to promote fuel diversification among the MSU operating com-

panies, to reduce the cost of generating power by displacing oil- and gas-fired generation with nuclear fired generating, and to minimize differences in energy costs among the four MSU operating companies—is inadequate. New Orleans also argues that MSE's allocation scheme violates the general FERC rule that the peak demand responsibility method should be used in allocating fixed plant investment costs. New Orleans advocates that the peak responsibility method be applied to allocate entitlements to Grand Gulf.

New Orleans notes that MSE's proposed allocation would be unduly discriminatory to NOPSI and its ratepayers because (1) NOPSI would be saddled with a larger proportionate share of Grand Gulf costs than either LP&L or MP&L, and (2) under the new system agreement (now pending before Judge Head in FERC Docket No. ER82-483-000) and MSE's proposed allocation of Grand Gulf, NOPSI will be required to buy proportionately more Grand Gulf capacity than any other company on the MSU system and then be required to sell proportionately more capacity from its existing low-cost oil- and gas-fired units to the MSU pool than either LP&L or AP&L (new Orleans Initial Brief, pp. 49-50).

The Mississippi Commission makes a somewhat different argument against MSE's allocation proposal than New Orleans, LPSC and Occidental. MPSC claims the Middle South system through MP&L made a representation to the Mississippi Commission at the time MP&L requested and obtained from the Mississippi Commission a certificate of public convenience and necessity for the construction of Grand Gulf. At that time, claims MPSC, Middle South represented that Grand Gulf would be subject to the 1973 Middle South System Agreement. Under that Agreement Grand Gulf would be a participation unit and "... the allocation of Grand Gulf capability was projected to be variable based on the shifting demands of the operating

companies, additions to capability, and retirement of units in the future" (MPSC Initial Brief, p. 26).

MPSC argues that the Federal Energy Regulatory Commission should deny MSE's proposed allocation and require MSE to adhere to the representations MSE made to MPSC when it sought the certificate of public convenience and necessity for Grand Gulf.

MSE's basic position is that its allocation proposal is justified because it would (1) reduce the reliance and dependence of the MSU operating companies on oil- and gas-fired generation, (2) move each MSU operating company toward the goal of having each company own a share of coal and nuclear base generating capacity proportionate to its average system load, (3) reduce the difference in the fuel prices of the MSU operating companies, and (4) diversify the kinds of fuel used in the MSU system in generating electricity.

In determining whether MSE's allocation proposal in the Unit Power Sales Agreement is just, reasonable, and not unduly discriminatory, we turn first to the standards of the Federal Power Act ("FPA").

Section 205(a) of the FPA, 16 U.S.C. §824d(a), establishes a threshold requirement that all of a public utility's rates and charges shall be "just and reasonable," and it declares unlawful any rate not comporting with this standard. Section 205(b), 16 U.S.C. §824d(b), provides:

> No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

Section 206(a), 16 U.S.C. §824e(a), "summarizes these prohibitions in the shorter phrase, 'unduly discriminatory or preferential.' " *Central Illinois Public Service Co.*, 20 FERC ¶61,043, p. 61,087 (July 12, 1982), *reh'g and stay denied,* 20 FERC ¶61,435 (Sept. 30, 1982). When FERC determines that a rate or charge is "unjust, unreasonable, unduly discriminatory or preferential," the Commission is directed by Section 206(a) to "determine the just and reasonable" rate or charge "to be thereafter observed and in force," and to "fix the same by order."

Courts have stated frequently that the principal purpose of the FPA "is to protect power consumers against excessive prices." *Pennsylvania Water & Power Co. v. F.P.C., 343 U.S. 414, 418 (1952); accord, Municipal Light Boards v. F.P.C.*, 450 F.2d 1341, 1348 (D.C. Cir. 1971), *cert. denied,* 405 U.S. 989 (1972). Similarly, it has been stated that Congress' "overriding intent" in enacting the National Gas Act ("NGA"), 15 U.S.C. §717, *et seq.*, was "to give full protective coverage to the consumer as to price." *Atlantic Refining Co. v. Public Service Comm'n,* 360 U.S. 378, 389 (1950); *accord, City of Chicago v. F.P.C.,* 458 F.2d 731, 751 (D.C. Cir. 1971), *cert. denied,* 405 U.S. 1074 (1972). *See also F.P.C. v. Hope Natural Gas Co.,* 320 U.S. 591, 610 (1944) (primary aim of NGA was "to protect consumers against exploitation at the hands of natural gas companies"); *Episcopal Theological Seminary v. F.P.C.,* 269 F.2d 228, 236 (D.C. Cir. 1959), *cert. denied,* 361 U.S. 895 (1959).

Sections 4 and 5 of the Natural Gas Act, 15 U.S.C. §§717c and 717d, are "virtually identical" to Sections 205 and 206 of the FPA. *United Gas Co. v. Mobile Gas Service Corp.,* 350 U.S. 332, 346 (1956). Precedents under the NGA are "plainly applicable" to the FPA. *Municipal Light Boards. v. F.P.C.,* 450 F.2d at 1341, 1347.

Disparate rates are legitimate under Section 205(d) of the FPA if sufficient factual bases exist to justify the

difference. *St. Michaels Utilities Commission v. F.P.C.*, 377 F.2d 912, 915 (4th Cir. 1967); *see also Metropolitan Edison Co. v. F.E.R.C.*, 595 F.2d 851, 857, 858 (D.C. Cir. 1979); *City of Frankfort v. F.E.R.C.*, 678 F.2d 699, 706 (7th Cir. 1982). MSE's proposed allocation of Grand Gulf would cause a large difference in the cost of nuclear capacity among the MSU operating companies and in the rates their consumers would have to pay. This disparity should not be permitted unless it is supported by adequate factual differences. I do not find such support in this record.

As noted earlier, the evidence of Middle South's witnesses is overwhelming that the Middle South system is a single integrated and coordinated electric system operating in Louisiana, Mississippi, Arkansas and Missouri. Planning, construction, and operations are conducted for the system as a whole. Loads on the system are met by centrally dispatching the most economical mix of generators wherever located in the system. Middle South Utilities, Inc. owns the stock of the operating utilities as well as the stock of MSS and MSE. When difficult system decisions have to be made, such as deciding the allocation of Grand Gulf, it is the Board of Directors of Middle South Utilities, Inc., that ultimately makes the decision, not an individual subsidiary company or a group of subsidiaries.

The Grand Gulf project was initiated in the 1970's to meet the then projected demand on the Middle South system by the end of that decade and not just the load of any Middle South operating company or companies. Constructing generation to meet system load was true of every unit constructed on the Middle South system (Tr. 756, 1293-4).

Under these circumstances the costs of Grand Gulf capacity and energy should be shared equitably by MSU's operating companies and their customers.

The concept of equitable sharing of system costs on an integrated electric system has been recognized and adopted

by FERC for a number of years in a long line of cases which roll in the costs of transmission lines serving integrated electric systems. *Potomac Edison Company,* 20 FERC ¶63,060, *aff'd,* 23 FERC ¶61,106 (1983), 23 FERC ¶61,398 (1983); *Southern California Edison Company,* Opinion No. 145, 20 FERC ¶61,301, pp. 61,588-61,589 (1982); *Southern California Edison Co.,* Opinion No. 821, 59 FPC 2167 at 2179-2180 (1977), *reh. denied,* 2 FERC ¶61,018 (1978); *Florida Power & Light Co.,* Opinion No. 784, 56 FPC 3581, 3605 (1976); *Public Service Company of Indiana,* Opinion No. 783, 56 FPC 3003, 3035-3036 (1976); *Union Electric Company, Opinion No. 609, 47 FPC 144, 151, 172 (1972).*

Generation capacity costs also have been rolled in by this Commission, with the capacity costs being allocated on the basis of relative peak demands. Arizona Public Service Company, Opinion No. 177, 23 FERC ¶61,419 (June 23, 1983); *Commonwealth Edison Co.,* Initial Decision (Phase I), 15 FERC ¶63,048 (June 3, 1981), *aff'd* Opinion No. 165, 23 FERC ¶61,219 (May 12, 1983); *Minnesota Power & Light Co.,* Opinion No. 20, 4 FERC ¶61,116 (Aug. 3, 1978); *Carolina Power & Light Co.,* Opinion No. 19, 4 FERC ¶61,107 (Aug. 2, 1978); *Alabama Power Co.,* Opinion No. 54, 8 FERC ¶61,083 (Aug. 1, 1979); *Florida Power & Light Co.,* Opinion No. 784-A, 58 FPC 2594 (June 14, 1977).

The rationale for the rolled-in method was stated in *Otter Tail Power Company,* Opinion No. 93, 12 FERC ¶61,169, p. 61,420 (1980):

> ". . . Commission precedent strongly favors use of the rolled-in method of transmission allocation. Given a finding that the system operates as an integrated whole, transmission costs have generally been rolled-in, absent a finding of special circumstances. The principal reason behind adoption of this methodology is that an integrated system is designed to achieve max-

> imum efficiency and reliability at a minimum cost on a systemwide basis. Implicit in this theory is the assumption that all customers, whether they be wholesale, retail or wheeling customers, receive the benefits that are inherent in such an integrated system." [Footnotes omitted.]

The Commission has also used the rolled-in method for allocating facilities under the Natural Gas Act, 15 U.S.C. § 717, *et seq. Battle Creek Gas Co. v. F.P.C.*, 281 F.2d 42 (D.C. Cir. 1960); *see also, Michigan Consol. Gas Co. v. F.P.C.*, 203 F.2d 895, 901 (3rd Cir. 1953). Similarly, the costs of gas, purchased under Sections 311 and 312 of the Natural Gas Policy Act of 1978, 15 U.S.C. §§3371, 3372, have been rolled in. *LaClede Gas Company v. F.E.R.C.*, No. 83-4227 (5th Cir., Jan. 13, 1984).

When Grand Gulf Unit No. 1 and Waterford No. 3 begin to produce electricity in commercial quantities, the Middle South system will have total nuclear generating capacity as follows:

	MW	*Total Cost (\$ Billion)*	*Cost Per kW*
ANO 1 and 2	1694	\$0.9*	\$ 530
Waterford 3	1104	2.4	2,200
Grand Gulf 1	1125	2.5	2,200
Total System	3923	5.8	1,500

> *Based upon total investment as of December 31, 1981, rather than investment as of commercial operation date.

Under Middle South's proposed allocation of Grand Gulf Unit No. 1, the responsibility for this nuclear capacity would be shared by the system's four operating companies as follows:

	MW	Total Cost ($ Billion)
AP&L	1694	$0.9
LP&L	1538	3.4
MP&L	356	0.8
NOPSI	335	0.7
Total	3923	5.8

As a result of Middle South's proposal in this case, most of the high cost of nuclear power on the Middle South system would be borne by Louisiana ratepayers, while all of the low cost nuclear power would benefit Arkansas ratepayers. Middle South's proposed allocation translates into dramatic rate increases at the retail level in Louisiana and Mississippi. This result is inevitable under Middle South's proposal since the initial costs of power from Grand Gulf Unit No. 1 will be in the order of 14 cents per kilowatt-hour and 12 cents per kilowatt-hour for Waterford 3 (excluding CWIP costs already reflected in LP&L's rates), compared to an average total retail rate of 4.97 cents per kilowatt-hour for LP&L in 1982 (Tr. 893) and an average cost of power for AP&L from ANO Units 1 and 2 in the order of 3 to 4 cents per kilowatt-hour. Equally important, in the longer run MSE's proposal means substantially higher costs for LP&L, MP&L, and NOPSI than for AP&L.

Middle South's proposed allocation perpetuates, rather than rectifies, the discrimination caused by the timing of the construction of the nuclear units, based upon decisions reached by the MSU system, to the serious detriment of MSU's Louisiana and Mississippi ratepayers, who would pay about four times more for nuclear capacity than MSU's Arkansas ratepayers and substantially more in overall retail rates.

It is significant that MSE's allocation proposal represents a departure from the historical MSU system achieve-

ment of a proportionate sharing of total generation costs among the MSU operating companies. While all generation costs on the MSU system were not equalized under the 1973 System Agreement (only "participation" units were equalized), the effect of the 1973 System Agreement prior to Grand Gulf and Waterford 3 was generally to tend over time to keep generation costs roughly the same throughout the MSU system.

MSE's witness Stampley stated this conclusion as follows (Tr. 803):

Q. And the setting off of kilowatt against kilowatt under the agreement had the general effect of setting off costs, is that right?

A. For many years it did.

Q. Now, sir, even when the base load capability came in at perhaps $250 a kilowatt in the 1970s there were fuel savings associated with that base load, is that correct?

A. If that were a coal or nuclear unit it would be, yes.

Q. And as a matter of fact, in terms of costs to ratepayers, since the fuel savings went with the unit or the entitlement that goes with the unit, again there was a rough proportion of total costs associated with capability equalization, is that right?

A. That's right, plus the fact that the system is growing such that new units were needed on a frequent basis, and it tended to equalize itself because companies would alternately install new units.

(*See also* Mr. Trumps' testimony at Tr. 947.)

Mr. Louizelle, a witness for LPSC, also drew the conclusion that the 1973 System Agreement worked for many years to accomplish the objective of equalizing total costs. He said (Tr. 2201):

> [F]or many years under the System Agreement, you are dealing with plants that had a total cost per kilowatt-hour that were not significantly different from other plants on the system. So that while ANO 1 and 2 had higher capacity costs, White Bluff 1 and 2 had higher capacity costs, they had relatively low fuel costs, offsetting the high capacity costs.
>
> So that the System Agreement would work, and did work, even though we had timing differences in the placement if you will, of new generating capacity.

The reasons given by MSE for its allocation proposal are inconsistent with the traditional MSU system approach. Mr. Trumps stated that MSE's proposed allocation was designed to move each company toward its proportionate share of nuclear and coal capacity and to promote the equalization of fuel charges (Ex. 75, p. 6). However, the MSU system never attempted in the past to achieve a proportionate share in the location or ownership of its nuclear and coal capacity. All generators were built to serve the Middle South system as a whole and their location in the system was a matter of economics and convenience.

Moreover, the asserted desire of MSU to equalize fuel charges ignores the great increase in rates to NOPSI, MP&L and LP&L from Grand Gulf. Mr. Trumps asserts, for example, that NOPSI will have a lower fuel cost as a result of MSE'S proposed Grand Gulf allocation, but he fails to note that NOPSI's overall cost would increase 35 percent, even after "levelization," as a result of the proposed allocation, and that the disparity in the rates of the MSU operating companies will dramatically increase. NOPSI ratepayers are likely to take little comfort in a fuel "equalization" that disproportionately increases their share of generation costs.

The other argument made by MSE in favor of its allocation plan also is not persuasive. MSE argues that its

allocation will reduce the dependence of its operating companies on oil- and gas-fired generation and diversify the kinds of fuel used on the MSU system. But those goals can be achieved for the MSU system by having the system own more nuclear and coal units, wherever located on the MSU system. It is not important in reaching that system goal that such units be owned by a particular MSU operating company.

In any event, the reasons given by MSE to justify its allocation proposal are not persuasive when weighted against the profound undue discrimination caused by that allocation.

Based on the foregoing discussion, I hold that MSE's proposed allocation of Grand Gulf results in an unjust, unreasonable, and unduly discriminatory allocation of costs among the Middle South operating companies and the localities and customers served by the Middle South system.

We must now determine what is an equitable allocation of Grand Gulf among the Middle South operating companies. We deal only with Grand Gulf Unit No. 1 because of the ruling in the next section of this Initial Decision that FERC should not decide at this time the issue of the allocation of the costs of power and energy from Grand Gulf Unit No. 2.

It has been suggested that this Commission not only reject MSE's proposed allocation but in addition not establish another allocation of power from Grand Gulf. Thus the Mississippi Attorney General requests that the allocation of power from Grand Gulf as set forth in the Unit Power Sales Agreement be rejected, and that MSE and the MSU system operating companies be forced

> to immediately begin to work with the appropriate regulatory authorities in the respective governmental jurisdictions to resolve the allocation issue in the best

interests of *both* the customers, the various MSU System Operating Companies service areas and the MSU System.

(Mississippi Attorney General Initial Brief, p. 19; emphasis in original.)

The request of the Mississippi Attorney General is denied for the reasons aptly stated in the Reply Brief of MSE (pp. 81-82):

> The Commission cannot and should not abrogate its responsibility under the Federal Power Act in the manner prescribed by the Mississippi Attorney General. Section 206(a) of the Federal Power Act, 16 U.S.C. §824(e)a, states
>
> Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charges, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, *the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.* (Emphasis added.)
>
> Correspondingly, Section 205 of the Federal Power Act requires that the Commission, after hearing, "make such orders with reference [to the proposed rate schedule] as would be proper in a proceeding initiated after it had become effective."
>
> It is thus evident that the Commission may not simply reject the terms and conditions of a proposed rate schedule and require that all parties go back to the drawing boards to attempt to achieve a unanimous

resolution of the matters at issue. Rather, if the Commission finds that terms and conditions of a wholesale rate schedule subject to its jurisdiction are unjust and unreasonable, it must fix the proper terms and conditions to be observed.

Moreover, as a matter of policy, the Commission should not shirk its responsibility in the manner proposed by the Mississippi Attorney General. Each of the regulatory authorities which has intervened in this proceeding is advocating an allocation method which will reduce the allocation of power from Grand Gulf to the System Operating Company under its jurisdiction and reallocate it to utilities under some other jurisdiction. Under such circumstances, it is unlikely that a resolution of the issue satisfactory to all of these regulatory authorities could ever be achieved. Accordingly, as an unbiased decision maker, this Commission should property exercise its authority to approve an allocation of all the power from Grand Gulf which is just and reasonable.

The parties opposing MSE's proposed allocation have offered three alternative allocation proposals. Briefly, the three alternatives are the following: (1) MPSC proposes that the allocation be based upon the 1973 System Agreement under which Grand Gulf would be a participation unit; (2) New Orleans proposes an allocation of Grand Gulf power based on the present coincident peak demands of the MSU system operating companies; (3) LPSC and Occidental support an allocation of Grand Gulf power which would have the effect of assigning "... each operating company a share of the cost for nuclear capacity which is roughly proportionate to that company's relative share of system demand." (Occidental Initial Brief, p. 47.)

I find, for the reasons discussed hereafter, that the proposal of LPSC and Occidental is the most equitable allocation proposal in this record.

In Exhibit No. 124, LPSC's witness Louiselle proposed an allocation of Gulf Unit No. 1 as follows:

	%	*MW*	*Total Cost ($ Billion)*
AP&L............	36	405	0.9
LP&L............	14	158	0.4
MP&L	33	371	0.8
NOPSI...........	17	191	0.4
	100	1125	2.5

If the Grand Gulf capacity is allocated in the manner proposed by Mr. Louiselle, then the costs of all nuclear capacity on the MSU system are allocated to each operating company roughly in proportion to each company's share of system demand. This result can be seen in the following two tables. Thus, if Grand Gulf Unit No. 1 is allocated as proposed by Mr. Louiselle, the responsibility for all the nuclear capacity on the system, including ANO and Waterford, would then be as follows:

	Units	*MW*	*Total Cost Allocation ($ Billion)*
AP&L	ANO 1 & 2 Grand Gulf 1	2099	1.8
LP&L	Waterford 3 Grand Gulf 1	1262	2.8
MP&L	Grand Gulf 1	371	0.8
NOPSI	Grand Gulf 1	191	0.4
		3923	5.8

The result of this allocation of Grand Gulf is to give each operating company a share of the cost of nuclear capacity roughly proportionate to that company's relative

share of system demand, as shown below (compare "Total Cost Allocation" in the table above with "Total cost Responsibility" in the table below):

	*Demand Ratio**	*Total Cost Responsibility ($ Billion)***
AP&L	.33	1.9
LP&L	.44	2.5
MP&L....................	.15	0.9
NOPSI	.08	0.5
	1.00	5.8

*Based upon 1982 average demand compared to total system average demand (Ex. 124).

**Calculated by multiplying the demand ratio by total system nuclear capacity costs of $5.8 billion (for ANO 1 & 2, Waterford 3, and Grand Gulf 1).

If one compares the actual cost allocation to proportionate cost responsibility shown on the two tables above, it can be seen that even under the LPSC proposal LP&L will bear a higher share of nuclear costs than its demand ratio would dictate, while the other companies will bear correspondingly lesser amounts. This results from the fact that in Exhibit No. 124, Mr. Louiselle conservatively assumed a cost for Waterford 3 of $2.1 billion, rather than $2.4 billion (on the basis comparable to Grand Gulf's $2.5 billion cost estimate).

Focusing on nuclear capacity in allocating Grand Gulf does not disregard other system base load capacity. Mr. Louiselle testified that he did take into account the costs of non-nuclear generation on the system in making his recommendation for Grand Gulf (Tr. 2226-7) because his allocation recognizes that while there are some differences in costs of non-nuclear generation among the generating companies, the cost differences are relatively minor compared to the cost differences for nuclear generation.

The record indicates that the costs of generation from base loaded non-nuclear units on the Middle South system are roughly equivalent. The cost per kilowatt-hour of coal-fired generation is in the order of 4 to 4.5 cents. By contrast, the cost of nuclear generation is not equal and for the newest nuclear units is much higher than other generation. Generation from AP&L's ANO units is on average about 2.5 to 4 cents per kilowatt-hour while the Waterford 3 and Grand Gulf 1 units are expected to come on line at 10 to 14 cents per kilowatt-hour. Exhibit No. 125 shows that AP&L's coal units produce electricity at a somewhat lower cost per kilowatt-hour than LP&L's oil units. Mr. Louiselle testified that the cost per kilowatt-hour of electricity from LP&L's other major oil- and gas-fired units (Little Gypsy and Ninemile Point) were comparable to the cost per kilowatt-hour of Waterford Units 1 and 2 (Tr. 2226). Moreover, the differences in costs per kilowatt-hour of non-nuclear base load generation are in AP&L's favor, and therefore a focus only on nuclear capacity is equitable in the context of this proceeding (Tr. 2216-29).

Mr. Louiselle testified that "the only rational approach is to look at today's facts and conditions as tempered by what we can reasonably expect for the future." (Tr. 2208.) That standard appears to be an appropriate one rather than basing the allocation on conditions and expectations at some earlier time. Grand Gulf Unit No. 1 will come on line at a cost per kilowatt which is far greater than was originally projected in the early 1970's and also hundreds of millions of dollars greater than was anticipated when the allocation decision was made in January 1980 (Tr. 1328-9, 1339). Its cost is hundreds of millions of dollars greater than it was when Middle South filed its direct testimony in the instant as in October 1982. It is also clear that the expectations of oil prices and, correspondingly, the expected benefits from Grand Gulf Unit No 1 have declined significantly from the time of the allocation decision in

January 1980 (Tr. 1331-2). There is also no doubt that in its early years of operation, Grand Gulf will cost on a per kilowatt-hour basis vastly more than existing alternative sources of generation on the Middle South system (Tr. 1085). Contrary to the approach proposed by Middle South, the allocation proposed by LPSC and Occidental deals directly and equitably with these facts to assure a just, reasonable and not unduly discriminatory result for all the operating companies and their ratepayers.

The LPSC proposal is consistent with the view of Middle South as a single, integrated system. The record in this case leaves no doubt that the Middle South system is organized, planned, and operated as a single, fully integrated electrical system. Each of the operating companies is owned by a single, common entity—MSU. Middle South's witnesses testified that "generation, transmission and distribution facilities of AP&L, LP&L, MP&L and NOPSI are integrated to form the Middle South System." (Ex. 1, p. 2.) The system is operated as "one electrical system under one ownership" (Tr. 347), with planning, construction and operation of generating units (including decisions as to the type, size, location and fuel) performed on the basis of a single system. In particular, the decision to build Grand gulf was a "system decision."

Although there are four separate companies operating at the retail level, Middle South is, and must be considered in this proceeding, "as a single electric system [operating] without regard to company or state lines in order to obtain the lowest possible cost of power supply consistent with a high degree of service reliability." *See Alabama Electric Cooperative & Alabama Power Company*, Opinion No. 533, 38 FPC 962, 966 (1967).

By way of contrast, certain power pools consist of a voluntary group of unaffiliated companies. An example of this type of power pool is the Pennsylvania-New Jersey-Maryland (PJM) pool. The companies which make up that

pool have joined together to achieve certain efficiencies in the generation and economic dispatch of electric power. Each member of th PJM pool is an unaffiliated entity and has complete autonomy for decisions to build, defer, convert, or retire generating units, depending upon its own individual needs and its own system load characteristics (Tr. 2196-7). In the instant case, however, the testimony demonstrates that individual operating companies within the Middle South system do not have the same autonomy or authority with respect to the planning and construction of generating units, and instead, that all such decisions are made on a system basis with the Board of Directors of MSU holding and exercising the ultimate decisional authority, which, for example, it exercised in allocating Grand Gulf.

The LPSC proposal is also consistent with this Commission's preference for rolled-in pricing, which we have previously discussed. One of the effects and goals of rolled-in pricing is to treat new customers and old customers equitably. Thus in *Battle Creek Gas Co. v. F.P.C.*, 281 F.2d 42 (D.C. Cir. 1960), the court recognized that a customer should not receive an unfair advantage merely because it was the first to receive service. The court said (281 F.2d at 46):

> The rolled-in rate method is generally disadvantageous, however, to old customers of an expanding pipeline. The cost of new facilities and new gas historically has risen steadily, and a rolled-in rate requires old customers to pay a higher price and bear part of the cost of an expansion from which they receive little visible increase in service. But, conversely, use of the rolled-in approach ensures that two otherwise similar customers will not pay radically different prices for commingled gas coming from the same pipe, merely because one happens to have been receiving the service longer than the other. Use of

> the rolled-in method thus serves the interest of equal treatment for customers receiving equal service.
>
> [Citations omitted.]

This rationale is applicable to the claims of the Arkansas intervenors who argue that they should not have to pay for an equitable share of Grand Gulf.

The LPSC and Occidental allocation proposal also has the salutory effect of minimizing discrimination between current and future ratepayers on the MSU system. As noted earlier, it is clear that there will be a significant detriment from Grand Gulf power compared to available alternatives over the next ten years. As a result, current ratepayers on the Middle South system will, in effect, be making an "investment" through the rates they pay for Grand Gulf, with the hope that at some point in the future that investment will pay off in terms of lower rates for future ratepayers. That investment has been estimated to be in the order of $3 billion.

A significant equity problem arises because, should there be some benefits in the future, the ratepayers who will reap those dividends will not necessarily be the same ratepayers who made the investment. The problem is exacerbated by the magnitude of the detriment to current ratepayers and the speculative nature of the future benefits. (By contrast, when AP&L's units came on line, they provided net benefits to current ratepayers in a relatively short period of time (Tr. 1798-99, 2199-2200). Middle South proposes to place the entire burden on current ratepayers in Louisiana and Mississippi and relieve current Arkansas ratepayers. Although there is no remedy which would eliminate the discrimination between current and future ratepayers, equitable sharing of these costs system-wide will reduce the amount of the subsidy to be paid by individual ratepayers. The LPSC proposal would spread this burden equitably among all the system's current ratepayers and mitigate the adverse impact on any individual ratepayers.

MPSC takes the position that Grand Gulf Unit No. 1 should be allocated as a "participation unit" under the 1973 System Agreement. Under this approach there would not be fixed allocations of Grand Gulf among the operating companies. Instead, MSE would become a party to the 1973 System Agreement, and Grand Gulf Unit No. 1 would be proportionally allocated to the "short" operating companies pursuant to the terms of the 1973 System Agreement. Thus, Grand Gulf Unit No. 1 would in effect became a floating unit, the responsibility for which would be constantly changing from month to month as particular operating companies became "shorter" or "longer."

The MPSC and the Mississippi Attorney General assert that the use of the "participation unit" concept under the 1973 System Agreement for the allocation of Grand Gulf was "represented to and accepted by the MPSC" as part of its grant to MP&L and MSE of a certificate of public convenience and necessity in 1974 to construct and operate Grand Gulf. The Mississippi parties apparently contend that any allocation procedure other than that represented to and accepted by the MPSC in its proceedings in 1974 would be contrary to the jurisdiction and authority of the MPSC and beyond the jurisdiction of this Commission to change.

The assertion that the MPSC approved—or even had the authority to approve—any allocation of the capacity and cost of Grand Gulf 1 in 1974 is not tenable. While MP&L and MSE did make certain representations to the MPSC during the course of the certificate proceedings in 1974 as to how Grand Gulf 1 might be treated under the 1973 System Agreement and allocated among the system operating companies, the MPSC in its order granting a certificate to MP&L and MSE did not specifically approve any particular allocation or allocation methodology for Grand Gulf or establish any particular allocation or allocation Methodology as a condition of the certificate (See Ex. 80).

Furthermore, MPSC did not have any authority to approve an allocation or allocation methodology for Grand Gulf. It knew that any proposed sale of Grand Gulf power and allocation of Grand Gulf costs was subject to review and approval by FERC under the Federal Power Act (Ex. 47, p. 15). Indeed, MPSC did recognize that the anticipated allocation of Grand Gulf represented to it by MP&L and MSE would have required an amendment to the System Agreement, and it knew or should have known that such revision was subject to this Commission's review and approval under the Federal Power Act.

MPSC further contends that Middle South's "overriding consideration" in allocating Grand Gulf was not to assign proportionate ownership of base load capacity but rather to insure adequate rate recovery for Grand Gulf for the Middle South system as a whole. In particular, MPSC cites "negative regulatory reactions in Louisiana" to the adoption of the participation concept as the basis for its rejection by Middle South (Initial Brief, p. 30).

It may be reasonable to conclude that rate support for Grand Gulf was a critical factor in Middle South's proposing a permanent, fixed allocation of Grand Gulf rather than the variable participation unit approach. However, the real issue is whether the result of this approach is just, reasonable and not unduly discriminatory under the Federal Power Act. Various witnesses testified that use of a variable "participation unit" approach would be unjust, unreasonable and discriminatory (Trumps, Tr. 1266, 2019; Perl, 1502; Louiselle, Tr. 2206-7, 2210-11, 2255-57, 2287; Ex. 130-C, p. 4).

As noted earlier in this Decision, for at least its first decade, Grand Gulf Unit No. 1 will be a net detriment to the operating companies to which it is allocated. The operating companies which are responsible for these high front-end costs should also receive on a proportionate basis the future benefits from Grand Gulf when and if they occur. These benefits will not accrue to these companies

under the variable participation unit approach. For example, under the MPSC proposal, LP&L would be required to pay 90 to 100 percent of the costs of Grand Gulf Unit No. 1 over the next ten years and then, under Middle South's projections, MP&L would assert its rights to such power when the costs are lower, both relatively and absolutely. MPSC recognizes this fact in its initial brief stating that MP&L would eventually grow into its allocation of Grand Gulf "without having to incur the high front-end capital costs of the Grand Gulf facility," and thus MP&L "would not have to ask for rate increases associated with Grand Gulf for the next five to eight years" (MPSC Initial Brief, pp. 37, 39). Such a result is unfair and unduly discriminatory when, under best case assumptions, the net detriment over the first 10-year period is in the order of $3 billion.

In addition, the MPSC proposal would cause fluctuating allocations of power for Grand Gulf among the Middle South operating companies and probably require more frequent retail rate proceedings in all Middle South jurisdictions by the operating companies.

New Orleans urges that Grand Gulf Unit No. 1 be allocated among the four Middle South operating companies for the life of the unit on the basis of their current relative peak demands as defined by each company's relative "responsibility ratio" as that term is used in MSU's most recently proposed system agreement in FERC Docket No. ER82-483. The responsibility ratio approach measures each MSU company's monthly peak load coincident with and in relation to the MSU system monthly peak (Tr. 1853, 2580-81). See New Orleans Initial Brief, p. 25.

In support of its proposal New Orleans basically argues that "in the first instance" the Grand Gulf project was initiated to meet projected system load growth, and the Commission has a well-established policy of allocating system demand-related costs on a peak responsibility method.

But there are problems with New Orlean's approach which, I believe, make it less equitable then the approach advocated by LPSC and Occidental.

First, New Orleans relies on the fact that the initial justification for building Grand Gulf was to meet projected load growth. In 1974, when construction was commenced, that was the case. However, the rationale for continuing construction and completing the unit changed over time. Middle South was constantly revising downward its load growth forecasts and reassessing its need for new capacity on the system to meet demand. The record indicates that the justification for continuing Grand Gulf changed from one of meeting system demand to one of fuel diversification and fuel replacement. It was determined that Grand Gulf Unit No. 1 capacity would not be necessary simply for Middle South to meet total system requirements—sufficient existing capacity existed to do that. Rather continuing construction of Grand Gulf Unit No. 1 was prudent because Middle South's executives believed Grand Gulf would enable the Middle South system to diversify its base load fuel mix and, it was projected, at the same time, produce power for a total cost (capacity and energy) which would be less than existing alternatives on the system.

Second, New Orleans mistakenly relies on Commission precedents which allocate capacity costs on the basis of relative peak demands. New Orleans cites, among other cases, *Arizona Public Service Company,* Opinion No. 177, 23 FERC ¶61,419 (June 23, 1983); *Commonwealth Edison Co.,* Initial Decision (Phase I), 15 FERC ¶63,048 (June 3, 1981), *aff'd* Opinion No. 165, 23 FERC ¶61,219 (May 12, 1983); *Minnesota Power & Light Co.,* Opinion No. 20, 4 FERC ¶61,116 (Aug. 3, 1978); *Carolina Power & Light Co.,* Opinion No. 19, 4 FERC ¶61,107 (Aug. 2, 1978); *Alabama Power Co.,* Opinion No. 54, 8 FERC ¶61,083 (Aug. 1, 1979); *Florida Power & Light Co.,* Opinion No. 784-A, 58 FPC 2594 (June 14, 1977).

The precedents cited by New Orleans involves the allocation of *all* the generation plant of a utility system. New Orleans, however, focuses solely on allocating one plant, Grand Gulf, while ignoring all other MSU system generating capacity and capacity costs. New Orleans' allocation does not produce a just and reasonable result because under its proposal the capacity costs on the MSU system are not equitably shared by the MSU operating companies.

The Arkansas Public Service Commission (APSC), the Arkansas Attorney General, the Arkansas Cities of Conway and West Memphis and International Paper Company ("Arkansas parties") argue that FERC lacks jurisdiction to allocate any portion of Grand Gulf power and costs to AP&L. The Arkansas parties attempt to depict AP&L as an independent utility which has expressly limited its involvement in the Unit Power Sales Agreement and which is a signatory for the circumscribed purpose of expressing its assent to the terms of the Agreement. (*See, e.g.*, International Paper Company, Initial Brief, p. 3 and n.; Arkansas Cities Initial Brief, p. APSC Initial Brief, p. 7.) The Arkansas parties contend that, notwithstanding the authority of the Commission to rectify undue preferences and discrimination under Sections 205 and 206 of the FPA, the Commission is powerless to allocate any responsibility for Grand Gulf power and costs to AP&L.

The arguments of the Arkansas parties start from a presumption that the Unit Power Sales Agreement is a voluntary contract resulting from arm's-length bargaining between unaffiliated utilities. The presumption is wrong. We are dealing with affiliated utilities wholly owned by MSU, whose board of directors decided the allocation in the Unit Power Sales Agreement.

AP&L, both as an individual entity and as an integral part of the Middle South system, has been a party to all of the understandings, agreements, and contracts entered

into with respect to Grand Gulf. AP&L executed and is a party to the Availability Agreement, as well as each of the amendments thereto, which were essential to the entire financing of Grand Gulf. Under the Second Amendment, AP&L agreed to bear a 17.1% share of Grand Gulf costs for purposes of adequate financing and completion of the project (Ex. 1, p. 15). AP&L executed and is a party to both the Reallocation Agreement (Ex. 20) and the Unit Power Sales Agreement which proposed specific allocations of Grand gulf power and costs. Indeed, AP&L is a necessary party to these agreements because it had prior rights to and obligations for Grand Gulf power and costs which were affected by the agreements, and which could not be altered without its consent. (See, e.g., Ex. 83). Moreover, both agreements specifically provide that the effectiveness of the proposed allocations is subject to the receipt of all necessary regulatory authorizations and approvals, including those of this Commission.

In addition, AP&L participated in the decision to establish MSE. AP&L participated in the same manner as every other MSU operating company in the decision to initiate construction of Grand Gulf. AP&L participated in the decisions to continue and complete construction of Grand Gulf. AP&L participated in the decision on the proposed allocation of Grand Gulf. AP&L, through the System Agreement and the System Operating Committee, has participated in the coordinated planning of generation additions on the MSU system. In view of the history of AP&L's deep and continuous involvement in every aspect of the decision to build, finance and allocate Grand Gulf, the Arkansas parties cannot come before this Commission now and effectively assert that AP&L is a wholly independent entity within the Middle South system which cannot be "required" to buy power from Grand Gulf. AP&L has been and is an active party and participant in the contracts and in the whole contractual process surrounding Grand Gulf to the same degree as LP&L, NOPSI and MP&L.

Section 206(a) of the Federal Power Act, 16 U.S.C. §824e(a), provides in pertinent part that, if the Commission finds that any *"contract affecting"* any jurisdictional "rate, charge, or classification, demanded, observed, charged, or collected by any public utility" is "unjust, unreasonable, unduly discriminatory or preferential," the Commission is directed to "determine the just and reasonable . . . *contract to be thereafter observed and in force,* and shall fix the same by order." (Emphasis added.) This explicit statutory directive clearly gives the Commission not only authority to supervise contracts among utilities, but also mandates that the Commission must revise the terms of such contracts to eliminate undue preferences or discrimination. The argument that the Commission lacks jurisdiction to adjust the allocation percentages in the Unit Power Sales Agreement cannot be reconciled with the Commission's duty under Section 206(a). The position of the Arkansas parties, if accepted, would also render meaningless the independent prohibition against undue discrimination embodied in Section 205(b), 16 U.S.C. §824d(b). *See Town of Norwood v. F.E.R.C.,* 587 F.2d 1306 (D.C. Cir. 1978). In *Town of Norwood.,* the Court rejected an interpretation of the *Sierra-Mobile* doctrine which would have precluded the Commission from revising a fixed-rate contract because that interpretation came "altogether too close to reading Section 205(b) out of the Federal Power Act in cases in which there is a *Sierra-Mobile* contract." 587 F.2d at 1312. Middle South, apparently recognizing the expansive scope of the Commission's statutory power, has acknowledged that "this Commission has full authority to review and approve the allocation percentages." (MSE Pretrial Brief, p. 34.) The Commission also has full authority to review and modify or reject those allocation percentages.

In asserting that the Commission lacks authority to modify the allocation of Grand Gulf to include AP&L, the Arkansas parties rely primarily on the companion cases, *United Gas Pipe Line Co. v. Mobile Gas Service Corp.,*

350 U.S. 332 (1956), and *F.P.C. v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956). Arkansas Cities argue that the Commission cannot "require MSE to sell to AP&L, nor require AP&L to buy from MSE, a portion of the capacity of Grand Gulf," but characterize this argument as "much different from one based on the *Mobile-Sierra* doctrine." (Initial Brief, pp. 8-9.)

In attempting to insulate the unlawful discrimination inherent in the Unit Power Sales Agreement from the Commission's scrutiny and remedial action, the Arkansas parties misunderstand the purposes of the *Mobile-Sierra* doctrine and misapply the limitations it places on the Commission's authority. Such an interpretation is unwarranted and inconsistent with the purposes of the *Mobile-Sierra* doctrine. In *Mobile* the Court's comments concerning the essentially voluntary nature of private rate contracts were not meant to suggest that the Commission lacked supervisory authority over these contractual arrangements, but were intended solely to highlight the "marked contrast" between these statutes and the premise underlying the Interstate Commerce Act, which "in effect precludes private rate agreements by its requirement that the rates to all shippers be uniform. . . ." 350 U.S. at 338. Indeed, the Court was careful to emphasize that its holding "in no way impairs the regulatory powers of the Commission, for the contracts remain fully subject to the *paramount power of the Commission to modify them when necessary in the public interest.*" 350 U.S. at 344 (emphasis added).

In *Sierra* the Court held that its interpretation of the Natural Gas Act in *Mobile* was "equally applicable" to the "substantially identical" provisions of the Federal Power Act. 350 U.S. at 353. The Court's opinion in *Sierra* evinces no intention to negate the Commission's jurisdiction over private rate contracts. To the contrary, the Court specifically acknowledge the "undoubted power [of the Commission] under §206(a) to prescribe a change in contract

rates whenever it determines such rates to be unlawful." *Id.*

In *Sierra* the Supreme Court described the circumstances in which the Commission could conclude, in a proceeding pursuant to Section 206(a) in which a public utility seeks an increase in a rate to which it has agreed by contract, that the contract should nevertheless be modified. Emphasizing that "the purpose of the power given the Commission by §206(a) is the protection of the public interest, as distinguished from the private interests of the utilities," the Court stated that:

> [T]he sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest—as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory. 350 U.S at 355.

The Court in the quoted passage was addressing the situation in which a public utility was unilaterally attempting to increase a fixed-rate contract with an unaffiliated customer. The purpose of the *Sierra* doctrine was not to protect "the private interests" of the utility but to protect "the public interest" of the ratepayers. The Court did not say that a contract could never be modified to rectify a statutory violation, such as undue discrimination. Instead, the Court reaffirmed the Commission's authority to remedy any undue discrimination arising out of a contract for the sale of wholesale electric energy.

It is clear from the record in this proceeding that the failure to allocate any portion of Grand Gulf power and costs to AP&L confers an undue preference on AP&L without factual justification and unduly discriminates against the other operating companies and their customers on the Middle South system. This failure fits within the "unduly discriminatory" component of the *Sierra* test and thus "adversely affect[s] the public interest," 350 U.S. at

355. *See Public Service Co. of Indiana v. F.E.R.C.*, 575 F.2d 1204, 1213 (7th Cir. 1978). To rectify the undue discrimination, AP&L should be allocated an equitable share of Grand Gulf in accordance with the proposal made by Mr. Louiselle. Such a remedy is consistent with the policy underlying the *Mobile-Sierra* doctrine.

Beyond the *Mobile-Sierra* doctrine, the separate prohibition against discrimination contained in Section 205(b) of the FPA compels the Commission to fashion an alternative remedy for AP&L's unduly preferential position created by the proposed allocations under the Unit Power Sales Agreement. *Mobile-Sierra* does not abrogate but reinforces FERC's power and responsibility under Section 205(b): "the mere presence of a *Mobile-Sierra* contract will not automatically shield any and all discriminatory treatment from attack under Section 205(b). . . . Rather, that section remains an independent force which must be accomodated." *Town of Norwood, supra*, 587 F.2d at 1311. The court in *Town of Norwood* stressed that nothing in *Mobile-Sierra* "permits a utility to use a fixed-rate contract as a device to render unassailable an otherwise prohibited undue preference. On the contrary, if such discrimination can be demonstrated, Section 205(b) requires that every effort be made to eliminate it." 587 F.2d at 1313.

The D.C. Circuit distinguished *Town of Norwood* in *Metropolitan Edison Co. v. F.E.R.C.*, 595 F.2d 851 (D.C. Cir. 1979), a case which is quoted extensively in the Arkansas Attorney General's Initial Brief (pp. 11-12). *Metro Edison* explicitly acknowledged the Commission's power under Section 205(b) to lower the rates charged customers who are not the beneficiaries of fixed-rate contracts, but pointed out that, unlike the situation in *Norwood*, none of the utility's customers had invoked Section 205(b) and claimed undue discrimination. 595 F.2d at 857 n.38. Accordingly, the court scrutinized the utility's request for an increase in the contractual rate by the standards applicable to proceedings under Section 206(a). The court concluded that

the public interest did not warrant an upward adjustment where the municipal customer in question had given "substantial and unusual consideration" for its fixed contract rate. *Id. Metro Edison* therefore fails to support the proposition that the allocations in the Unit Power Sales Agreement should remain inviolate.

In his initial brief (pp. 3-6), the Arkansas Attorney General quotes, without substantive discussion, extensive excerpts from two Courts of Appeals decisions which purportedly stand for the proposition that FERC possesses no jurisdiction to revise the terms of a voluntary contract among signatory utilities. The cited cases, however, refute this proposition, and, in fact, support an assertion of the Commission's jurisdiction in this case.

In *Municipalities of Groton v. F.E.R.C.*, 587 F.2d 1296 (D.C. Cir. 1978), a group of municipalities owning electrical systems argued that the failure of the New England Power Pool (NEPOOL) Agreement to include a provision for firm power sales unduly discriminated against small utilities. The municipalities' challenge was tantamount to a request that the Commission require that a provision for firm power sales be included in the Agreement, and it is noteworthy that the Commission's jurisdiction to order such a remedy was apparently unchallenged.

While the Arkansas Attorney General is correct that both the Commission and the Court of Appeals relied upon the voluntary nature of the NEPOOL Agreement in holding that the failure to provide for firm power sales was not unduly discriminatory, it is essential to focus upon the precise factual setting in which this conclusion was reached. Specifically, the Commission noted that the Pool Agreement had at one time included a provision for firm power sales which had been intertwined with the concept of pool supported transmission facilities ("PSTF"); however, when the parties could not agree on how the costs of PSTF were to be allocated, the latter concept was abandoned

along with firm sales. For this reason—and not because it doubted its authority to order insertion of an appropriate provision in the Pool Agreement if warranted by the evidence—the Commission declined to infer any discriminatory intention from the exclusion of firm sales.

Moreover, in a portion of the opinion which the Arkansas Attorney General fails to quote, the court implicitly recognized the Commission's authority, on appropriate evidence, to require that the Pool Agreement be revised to provide for firm power sales if such a contractual provision were found necessary to rectify unlawful discrimination. Thus, to support its finding "that the Commission's actions are the product of reasoned decisionmaking" warranting affirmance, the court was careful to observe that the Commission (587 F.2d at 1299-1300):

> did note in its orders that the participants have indicated that they were still considering PSTF and firm sales. It urged them to continue to explore the idea of firm power wheeling, *and cautioned that it would later scrutinize NEPOOL operations in order to reassess the feasibility of shifting to PSTF and firm sales as experience under the* agreement is gained. This approach is reasonable. . . . [Emphasis added.]

The underscored language clearly displays both the Commission's premise that it possessed statutory authority to require that the Pool Agreement provide for firm power sales and its willingness to exercise that authority when warranted by the facts. it is equally significant that the court relied upon this facet of the Commission's decision as one of the predicates upon which it hinged affirmance of the Commission's finding that no undue discrimination resulted from the failure to provide for firm power sales.

Similarly, *Central Iowa Power Cooperative v. F.E.R.C.*, 606 F.2d 1156 (D.C. Cir. 1979), refutes the position that the Commission lacks authority to revise the Unit Power Sales Agreement by allocating a portion of Grand Gulf to

AP&L. (The case is distinguishable in the first instance because it involved a voluntary regional power pool, not a fully integrated, commonly owned utility system.) The case involved a challenge to the Mid-Continent Area Power Pool (MAPP) Agreement, which had been signed by thirty-one electric power systems in order "to promote reliable and economical operation of the interconnected electric network in the mid-continent area. . . ." 606 F.2d at 1160. South Dakota argued that the MAPP Agreement was unreasonable under Section 206(a) of the FPA because the services offered by the pool were not as comprehensive as those offered by other pools, such as the New England Power Pool. Emphasizing the expressly voluntary nature of power planning arrangements under Section 202(a) of the Act, 16 U.S.C. §824a(a), the court held that the Commission lacked authority to mandate the expansion of pool services if all that was shown was "that a particular pool does not offer the same range of services as another pool. . . ." 606 F.2d at 1167. The court, however, was careful to note that the Commission "had specific responsibility in this proceeding to decide whether a particular voluntary pool agreement was unjust, unreasonable, or unduly discriminatory," *Id.* at 1167 n.33, and clearly stated that the Commission could force the participants in a power pool to offer expanded pool services if such a remedy were necessary to vindicate a violation of the statute:

> The Commission had authority. . .under section 206 of the Act. . .*to order changes in the limited scope of the Agreement, including the addition of pool services,* if, in the absence of such modifications, the Agreement presented "any rule, regulation, practice or *contract* [that was] unjust, unreasonable, unduly discriminatory or preferential." *Id.* at 1168. [Emphasis added.]

In short, the court confirmed the Commission's authority "to compel additional services" if a voluntary agreement among electric utilities is found to be unjust, unreasonable

or unduly discriminatory. *Central Iowa* thus furnishes direct support for the Commission's power to reallocate the percentages assigned to the operating companies on the Middle South system to correct the discriminatory nature of the Unit Power Sales Agreement.

Finally, the Arkansas parties rely heavily upon the Commission's decision rejecting an objection to a unit power sales agreement between Southern Company Services, Inc. ("Southern") and Florida Power and Light Company ("FP&L"). *Southern Company Services Inc.*, 20 FERC ¶61,332 (September 22, 1982). Arkansas Cities contend (Initial Brief, p. 8) that *Southern Company Services* stands for the proposition that "nowhere in the [Federal Power Act] is there found any power in the Commission to order a utility like AP&L to buy power from a particular source." The APSC (Initial Brief, pp. 9-11) makes a similar argument. The Arkansas Attorney General reads *Southern Company Services* even more broadly to establish that FERC "is precluded from reforming contractual agreements voluntarily entered into by regulated companies among themselves." (Initial Brief, p. 6.) However, the Arkansas parties' attempt to analogize the *Southern Company Services* case to this one disregards the fundamentally disparate legal and factual settings in the two proceedings, as well as the narrowness of the Commission's ruling.

In *Southern Company Services,* Seminole objected to a unit power sales agreement between Southern and FP&L on the grounds, *inter alia,* that (1) Seminole could sell unit power to FP&L cheaper than Southern and (2) failure of FP&L to buy Seminole unit power would drive Seminole's costs upward making it more difficult for Seminole to compete with FP&L for retail customers. The Commission in rejecting the argument noted that Seminole conspicuously failed to assert that the rates set forth in the unit power sales agreement were unjust and unreasonable or that any particular facet of the agreement was

unduly discriminatory or preferential. 20 FERC ¶61,332, p. 61,694.

The Commission was not called upon in *Southern Company Services* to determine what the appropriate remedy would have been if Seminole had alleged that its injury was a proximate result of conduct on FP&L's or Southern's part which violated the FPA. The Commission simply had no occasion to decide whether, positing a violation of the FPA, it had authority to remedy that unlawful conduct by rejecting the agreement between Southern and FP&L or by ordering the latter to purchase from Seminole. Accordingly, the Arkansas Attorney General is in error when he states that the Commission in *Southern Company Services* "determined that it *lacked the requisite jurisdiction* to require one of the parties to the proposed Unit Power Sales Agreement to purchase capacity from an intervenor." (Emphasis added.)

Moreover, there are important factual distinctions between *Southern Company Services* and the instant case. First, the unit power sales agreement in *Southern Company Services* did not involve a transaction among commonly owned affiliates on a fully integrated system. Second, Seminole's posture *vis-a-vis* the southern-FP&L agreement is distinctly different from AP&L's relationship to the Unit Power Sales Agreement under scrutiny in the instant case. Seminole was a wholly unrelated third party which was attempting to inject itself into a contractual relationship between two unaffiliated entities, and it apparently lacked any colorable basis in the FPA to challenge the contract between Southern and FP&L. In contrast AP&L is a signatory to the Unit Power Sales Agreement and has had a deep and continuing involvement in the planning, decision-making, construction, financing and allocation relating to Grand Gulf. Against this factual backdrop, the Commission has plenary authority under Sections 205 and 206 to remedy the undue discrimination resulting from the allocation provisions of the Unit Power Sales

Agreement. The arguments of the Arkansas parties to the contrary are not persuasive.

In his initial brief (pp. 13-14), the Arkansas Attorney General asserts that the Security and Exchange Commission's ("SEC") order approving the Reallocation Agreement preempts the Commission's review of the allocation of Grand Gulf provided for in the Unit Power Sales Agreement. The argument is without merit. The authority of the SEC and this Commission are not in conflict. The SEC has sole jurisdiction over MSE's financing transactions and, as explicitly recognized by the SEC (Ex. 2), FERC has exclusive jurisdiction over the approval of the allocation of Grand Gulf (*See* Ex. 1, pp. 15-16).

The Arkansas parties also contend that even if the Commission determines that it has authority to assign Grand Gulf capacity to AP&L, it should nevertheless refrain from doing so because it would be (1) contrary to Commission precedent, and (2) inequitable to AP&L and its ratepayers.

Commission precedent does not preclude assigning AP&L an equitable share of Grand Gulf Unit No. 1. In its initial brief (pp. 12-16), APSC argues that the Commission's decision in *Georgia Power Company*, Opinion No. 711, 52 FPC 1343 (1974), *reh'g denied*, 53 FPC 1103 (1975), precludes the Commission, as a matter of "binding precedent," from making an allocation of Grand Gulf power and costs to AP&L. The APSC argues from *Georgia Power* that "the independent corporate status of the operating companies must be honored." (Initial Brief, p. 16.) Accordingly, APSC insists, the Commission must treat the allocation of Grand Gulf set forth in the Unit Power Sales Agreement as conclusive and is precluded from exercising any power it might otherwise possess to reallocate a portion of Grand gulf to AP&L. For the Commission to disturb the allocation set forth in the Unit Power Sales Agreement, the APSC contends, "would ignore the independent status of the operating companies." (*Id.*)

The APSC erroneously reads *Georgia Power* as articulating an inalterable rule that precludes the Commission from disregarding corporate formalities in allocating costs, even when a failure to pierce the corporate veil would perpetuate undue preferences or discriminations violative of the FPA. This unsound result—which would substantially impair the Commission's authority to enforce Sections 205 and 206—is not what the Commission intended in *Georgia Power*. Moreover, APSC's position, that *Georgia Power* requires the Commission to defer to "the independent corporate status of the operating companies" in an affiliated pool, is squarely refuted by the court's observation in *Southern Carolina Generating Company v. F.P.C.*, 261 F.2d 915, 920 (4th Cir. 1958), that "[t]he Commission repeatedly looks through the corporate form of affiliated corporations joined in a single system to recognize economic realities."

Moreover, in *Georgia Power*, the Commission specifically observed (52 FPC at 1349):

> If electric utilities become more dependent upon large multi-company generating units which are remote from their service areas, it may become necessary to treat ratemaking upon a broader geographic basis.

In *Georgia Power* the Commission was not presented with the task of allocating the cost of a unit which had been planned and constructed on a system basis to meet system demand. However, it intimated unmistakably that, in the case of such "large multi-company generating units . . . which are remote from their service areas," system-wide costing would have to be used. Grand Gulf was planned and constructed by MSE, rather than an operating company, to meet MSU system load and is not dedicated to satisfying the discrete load of a particular operating company on the Middle South system. Thus the considerations motivating individual company costing in *Georgia Power* are inapposite in the context of this case.

The Arkansas parties also contend that assigning any responsibility for Grand Gulf Unit No. 1 to AP&L would be inequitable because: (1) AP&L does not need and cannot economically use more base load capacity; (2) AP&L will not receive a windfall from being relieved of all responsibility for expensive nuclear capacity on the system; and (3) the other operating companies need the full allocation of Grand Gulf 1 assigned to them. These arguments also are not persuasive.

The Arkansas parties assert that assigning any capacity from Grand Gulf Unit No. 1 to AP&L would result in AP&L having excess base load capacity. The result, it is argued, is that under the equalization provisions of the new proposed System Agreement (which went into effect in January 1983 pending Commission review in Docket No. ER82-483-000) AP&L's ratepayers would be required to support the higher capacity costs associated with nuclear and coal base load units but would not be able to fully use the correspondingly lower fuel costs. Instead, the argument continues, AP&L often would be providing cheap energy to the other operating companies through economy energy transactions and compensated only for fuel and incremental operation and maintenance costs, but receive no reimbursement for capacity costs.

The response to this alleged inequity is twofold. First, it is not clear that there is so-called "excess" AP&L base load capacity or, if there is, whether it is necessarily detrimental to AP&L.

In its initial brief (p. 22), the Arkansas Attorney General asserts that AP&L did not want to sell a portion of its interest in Independence 1 and 2 (44% or over 400 megawatts) to MP&L. This assertion is inconsistent with an argument that AP&L would have too much base load capacity if it were allocated some 400 megawatts of Grand Gulf Unit No. 1. If Mr. Louiselle's allocation proposal is ultimately adopted by this Commission, AP&L will be in

the same position with regard to base load capacity as it would have been if it had not sold a portion of its interest in Independence 1 and 2 to MP&L.

Even if we recognize that capacity costs associated with AP&L's nuclear and coal capacity are higher than oil- and gas-fired capacity and that some of that capacity will not always be needed to meet AP&L's own load, we find that AP&L's total cost per kilowatt-hour for generation is and will be for the foreseeable future less than that for its sister operating companies which rely upon oil- and gas-fired capacity and very expensive nuclear capacity (*see* Tr. 2229-33; Ex. 125; Occidental Initial Brief, pp. 21-25). For example, Dr. Perl estimated that the initial total cost of power from ANO 1 was about 2.2¢ per kilowatt-hour (Tr. 1798-9). This estimate was confirmed by Mr. Louiselle (Ex. 125). Moreover, the ANO, White Bluff and Independence units provided net benefits on a per kilowatt-hour basis to AP&L's ratepayers soon after they came on line compared to alternative sources of generation (Tr. 2199-2200, 2249-54, 1799; Ex. 84, p. 9, 11-12). As noted earlier, Mr. Lupberger stated that the "Arkansas customer is very fortunate" (Tr. 461), and, as Mr. Louiselle indicated, LP&L would be happy to have AP&L's "problem" (Tr. 2230-1).

Second, AP&L is not without alternatives if it believes that it has excess base load capacity. AP&L would have willing buyers among the other operating companies for substantial portions of its coal fired capacity (as well as for its ANO capacity) (Tr. 1357-8). AP&L could either sell part of its interest in a plant to another operating company (as it did with Independence 1 and 2) or it could make a unit power sale for that portion of its base load capacity which it felt was excess to its needs and be compensated fully for both its capacity and its fuel costs for that sale under Rate Schedule MSS-4 of the 1983 System Agreement (Tr. 1356, 2176, 2231; *see* Ex. 126). AP&L has been making such sales to LP&L and NOPSI on a short term basis pending completion and in-service operation of Grand

Gulf Unit No. 1 and Waterford 3 (Tr. 1241-4, 1740-1). With AP&L allocated responsibility for 405 megawatts of Grand Gulf Unit No. 1 as proposed by Mr. Louiselle, a unit power sale of its share of either White Bluff 1 or 2 (465 megawatts each) would keep AP&L in the same position as it is now *vis-a-vis* base load capacity responsibility.

The Arkansas parties also argue that AP&L and its ratepayers deserve to escape any responsibility for expensive nuclear capacity on the system because AP&L has already built sufficient base load capacity to meet its own needs. The Arkansas parties assert that Middle South has always built new generation, first, to meet the needs of the operating companies and, second, to meet the needs of the system as a whole. AP&L, they continue, determined to build the ANO nuclear units and the White Bluff and Independence coal units while the other operating companies "chose different paths in plant construction." (Arkansas Attorney General Initial Brief, p. 17.) Moreover, they argue, AP&L and its ratepayers financed, at considerable hardship, this construction program, and AP&L should not now have to share these units with other system operating companies.

This argument overlooks the fact, well-established on this record, that generation capacity additions on the Middle South system are planned for and added for the benefit of the system as a whole. In particular, the decisions to build ANO and the coal units in Arkansas were system decisions (Tr. 742, 746, 1294, 2152-3, 2157). Similarly, the decisions not to build or to delay construction of other base load units to be constructed by the other operating companies have been system decisions (Tr. 2155-7).

While there is no doubt that AP&L was assigned responsibility to construct these units and was required to obtain the debt financing to support them, the Arkansas parties ignore several significant facts. First, these units

came on line at a total cost (capacity and fuel) which was competitive with existing oil- and gas-fired generation of the system (Tr. 936, 1287). Although AP&L ratepayers may have paid higher capital costs, they paid lower fuel costs than the ratepayers served by the other operating companies on the system. It is clear that AP&L is currently better off and will continue to be better off with ANO over its life than LP&L and MP&L are and will be with their oil and gas fired units (Tr. 1286-7). The Arkansas parties' analysis is misleading since it is total costs with which the ratepayers are most vitally concerned (Tr. 2159).

Second, the Arkansas parties ignore the fact that at the same time AP&L was financing its construction program, LP&L was experiencing severe financial difficulties in having sole responsibility for construction of Waterford 3 (Ex. 97, p. 8). Thus while AP&L was constructing 2048 megawatts of nuclear and coal capacity in four different units in the middle to late 1970's at a total cost of $1.1 billion (*see* Ex. 98: ANO 2—858 megawatts, $608 million; White Bluff 1 and 2—930 megawatts, $341 million; Independence 1—260 megawatts, $156 million), LP&L was constructing 1104 megawatts of nuclear capacity in one unit at a cost of $2.4 billion.

Third, the magnitude of the total cost of power from the new nuclear units—Grand Gulf Unit No. 1 and Waterford 3—are not comparable to the cost of any other base load generation on the system. Similarly, the burden that would be imposed on LP&L as a result of its allocated responsibility for those units—over $3 billion—is not comparable to the cost burden of AP&L's base load capacity, particularly if the megawatt capacity made available and the fuel mix achieved as a result of that burden are taken into account.

Fourth, AP&L has not financed its base load units unassisted. ANO 2 was a "participation unit" for a brief

period. White Bluff 1 and 2 were not only "participation units' from the time they went into service, but they also have been the subject of unit power sales since the "participation unit" provision in the System Agreement was terminated (See Exs. 98 and 121). White Bluff 1 went into service in August 1980 and was a participation unit from that date through December 1982. White Bluff 2 went into service in July 1981 and was a participation unit from that date through December 1982. A portion of AP&L's interest in Independence 1 and 2 was purchased in June 1981 by MP&L, which assumed its proportionate responsibility for construction financing from that date (Ex. 84, pp. 7-8).

Finally, even under Mr. Louiselle's proposed allocation, AP&L will still have the lowest total cost of generation on the system.

7. Conclusion

Based on the foregoing discussion it is held that the Unit Power Sales Agreement shall be modified so that the Entitlement Percentages for Grand Gulf Unit No. 1 will be as follows:

	Entitlement Percentages Grand Gulf Unit No. 1
AP&L........................	36%
LP&L........................	14%
MP&L........................	33%
NOPSI........................	17%

I find that these modified entitlement percentages are just, reasonable and not unduly discriminatory.

It is further held, based upon the discussion in the next section of this Decision, that the Unit Power Sales Agreement shall not designate any Entitlement Percentages for Grand Gulf Unit No. 2.

B. Allocation of Grand Gulf Unit No. 2

The next issue is whether the Federal Energy Regulatory Commission at this time should decide the allocation of power and energy and of the costs of power and energy from Grand Gulf Unit No. 2 (Tr. 251).

MSE urges that the allocation percentages set forth in the Unit Power Sales Agreement for Grand Gulf Unit No. 2 be approved. New Orleans, Occidental, LPSC and Staff argue that no allocation be made at this time.

In a subsequent section of this Initial Decision we hold that the costs of Grand Gulf Unit No. 2 shall not be included in the automatic adjustment clause of the Unit Power Sales Agreement essentially for the reasons that the construction of Unit No. 2 is not sufficiently advanced, its ultimate costs are not known, and completion of the unit is speculative. These reasons also argue for not making any allocation of Unit No. 2 at this time. In addition, the reasons for making an equitable allocation and the way such an allocation should be made can be seen more clearly at the time Unit No. 2 nears completion. The rationale today for making an allocation today of Unit No. 2 may not be valid when the Unit is completed; a different allocation based on a different rationale may then be appropriate.

It is therefore held that no allocation of power and energy and of the costs of such power and energy from Grand Gulf Unit No. 2 shall be made at this time.

C. The Automatic Adjustment Clause

The third issue is whether good cause has been shown for the use of an automatic adjustment clause in the Unit Power Sales Agreement (Tr. 249).

The Unit Power Sales Agreement (Ex. 7) includes a formula for pricing the sales of power to the three purchasing MSU system companies. The Agreement provides

that in consideration of the right to receive its "Entitlement Percentage" of power from each of the Grand Gulf units, each purchaser will pay MSE an amount equal to the purchaser's Entitlement Percentage multiplied by MSE's "Total Cost of Service" for the unit for the month (Ex. 7, p.2). The "Total Cost of Service" for each unit for any month is defined as the sum of (a) MSE's operating expenses for the month for the unit, plus (b) an amount equal to one-twelfth of the Composite Percentage multiplied by the Net Unit Investment for the unit (Ex. 7, p. 2; Ex. 8; Ex. 62, p. 5).

MSE's operating expenses include for each unit all amounts properly chargeable to operating expense accounts in accordance with the FERC Uniform System of Accounts including depreciation accruals, amortization of nuclear fuel leases, spent nuclear fuel disposal costs, maintenance expenses, taxes, gains/losses from disposition of utility plant, and accruals of provision for decommissioning (Ex. 5, p. 5; Ex. 8).

Several items of the formula are fixed and are not subject to change without a rate change filing with the Federal Energy Regulatory Commission. These items are the rate of return on common equity, the rate at which depreciation expense is accrued, and nuclear decommissioning costs (Ex. 5, p. 5). The remaining items adjust automatically up or down as their values increase or decrease (Ex. 5, p. 5).

In its Prehearing Brief the Louisiana Public Service Commission took the position that "[t]he automatic adjustment clauses should be approved only if MSU is able to show good cause for their adoption" (LPSC Prehearing Brief, p. 10).

However, at the hearing no party submitted evidence challenging MSE's cost-of-service formula, although some parties proposed revisions to the formula or restrictions on its application.

MSE tendered two witnesses, Mr. Brown and Mr. Lupberger, on the automatic adjustment clause issue. Mr. Brown explained that MSE chose a cost-of-service or formula tariff generally because MSE is a one-asset company and would have confronted impossible financing obstacles if it did not have an assured stream of revenues adequate to cover its operating expenses and return obligations (Ex. 5, pp. 2-3; Tr. 583-85). He stated that it is important that MSE recover its costs, including cost of capital, in order to establish a record of earnings coverage which will be looked upon favorably by potential investors in the next few years when MSE seeks large amounts of capital for permanent financing (Ex. 5, pp. 14-15; Tr. 584). MSE patterned its cost-of-service agreement after those already on file for the Yankee companies because in MSE's opinion they conform closely to Commission policy (Ex. 5, p. 3; Tr. 564). Mr. Brown stated that MSE personnel attempted to insure that the proposed rate would produce an exact cost recovery (Ex. 5, p. 14) and that the proposed agreement would result in fairness to all parties involved because it provides for both upward and downward adjustments in the cost of service. (*Id.*, p. 15; Ex. 62, pp. 4-5; Tr. 558.)

Mr. Lupberger emphasized that the part of the formula rate providing for flow-through of interest charges is important because there is no way of predicting what MSE will be required to pay under its financing agreements given the volatility of interest rates (Ex. 1, pp. 19, 21). Any failure of MSE to meet its financial obligations after Grand Gulf goes on line would erode investors' and creditors' confidence thereby making future investment in MSE more risky, impairing its ability to obtain additional bank loans or other short-term financing, and making any funding more costly (Ex. 61, p. 4). In addition, Mr. Flaherty, testifying for the Mississippi Public Service Commission, admitted that the cost-of-service rate has merit for a single asset utility (Tr. 2568).

The only evidence to possibly counter MSE's testimony were certain statements of Mr. Brown brought out on cross examination to the effect that if a cost-of-service rate is permitted in this docket as proposed, amounts in the formula will be changed without regulatory involvement (Tr. 569-70; 576); in addition, changes will be made by MSE personnel (Tr. 573; 576-77). However, counsel's cross examination also revealed that these changes will be based on the Uniform System of Accounts (Tr. 577; 579-80), and under the Uniform System of Accounts activity in certain accounts requires Commission approval (Tr. 580).

Automatic adjustment clauses are exceptions to the notice and review provisions of the Federal Power Act. The Commission can make such exceptions "for good cause shown." 16 U.S.C. §824d(d). The question here is whether the evidence in this case meets the "good cause" requirement of the statute.

In *Central Power & Light Co.*, 11 FERC ¶61,102 (1980), the Commission reaffirmed its authority to approve automatic adjustment clauses. Noting that such clauses are exceptions to the notice and review provisions of the Federal Power Act, the Commission stated (pp. 61,227-8):

> [I]n order to remove the changes in charges under an 'automatic' clause from the notice, filing and suspension provisions of Section 205, the Commission must expressly approve the clause as the rate rather than merely accepting the contract containing the clause.

The Commission listed the kinds of tariffs in which it had allowed and would continue to allow an automatic adjustment clause to operate as the rate, including "certain full cost of service formula tariffs (particularly for unit sales and sales to affiliates)." *Id.* p. 61,228.

The Commission found good cause to approve a proposed formula as the rate in *Middle South Services, Inc.*, Opinion No. 124, 16 FERC ¶61,101 (1981). There the

agreement between the operating subsidiaries of Middle South Utilities contained both capability and transmission cost equalization formulae by which the operating companies having excess generating or transmission capacity sold the excess to companies having deficient capacity. Under the formulae ultimately approved by the Commission, all costs relating to the sales, except rate of return on common equity, adjusted automatically as their values increased or decreased. The Commission found that good cause existed for acceptance of the formulae because "the proposed formulae provide for upward and downward adjustments in essentially all of MSS' costs, and because the sales involved are among affiliates operating on a pool basis." 16 FERC ¶61,101, p.61,219.

On appeal by the Louisiana Public Service Commission, the court affirmed the FERC's conclusion that good cause for accepting the formulae as the rate had been shown. *Louisiana Public Service Comm'n v. F.E.R.C.*, 688 F.2d 357, 360-361 (1982), *cert. denied,* 103 S. Ct. 1770 (1983).

MSE's Unit Power Sales Agreement was patterned after the power sales agreements of Connecticut Yankee Atomic Power company, Maine Yankee Atomic Power Company, Vermont Yankee Atomic Power company and Yankee Atomic Electric Company (Ex. 5, p. 2-3; Ex. 6, p. 2). Such cost-of-service tariffs have been approved for unit sales. *Connecticut Yankee Atomic Power Co.,* Opinion No. 102, 13 FERC ¶61,154 (1980); *Indiana & Michigan Power Co.,* Opinion No. 27, 4 FERC 61,316 (1978).

Based on the foregoing discussion, I find that good cause has been shown for the use of an automatic adjustment clause in the Unit Power Sales Agreement which is the subject of this case.

D. Grand Gulf Unit No. 2 and the Automatic Adjustment Clause

The fourth issue is whether the costs of Grand Gulf Unit No. 2 should be included in the automatic adjustment clause of the Unit Power Sales Agreement (Tr. 249).

The Agreement contains the rates, terms and conditions of service for the sale of power from Grand Gulf Unit No. 2 as well as Grand Gulf Unit No. 1, and the automatic adjustment provisions apply to both units.

MSE urges that the automatic adjustment clause of the Unit Power Sales Agreement be approved for Unit No. 2 as well as Unit No. 1 (MSE's Initial Brief, Section II.N., pp. 143-49; *see also* Tr. 581 and statement of counsel at Tr. 221, *et seq.*). MSE's position is opposed by Staff, Occidental Chemical Corporation and the Louisiana Public Service Commission.

MSE argues in essence that Grand Gulf Unit No. 2 will save hundreds of millions of dollars over its life based on estimated costs of alternative sources of power; that the incremental cost to complete Grand Gulf Unit No. 2 is much less than the cost of constructing coal-fired generating facilities; that a substantial part of the facilities common to Grand Gulf Unit No. 1 and Grand Gulf Unit No. 2 have been completed; that it will be easier for the operating companies scheduled to receive power from Grand Gulf Unit No. 2 to acquire their proportionate shares of baseload capacity and to plan for acquisitions or retirements of generating capacity if Grand Gulf Unit No. 2 is built than if it is not built; and that obtaining funds to finish constructing Grand Gulf Unit No. 2 and to refinance existing debt will be easier if the automatic adjustment clause is approved now for Grand Gulf Unit No. 2 rather than at some later time.

MSE also argues that its position is supported by a Federal Power Commission letter order dated December

18, 1964, involving Connecticut Yankee Atomic Power Company and an order on rehearing in *Tucson Electric Power Company,* 7 FERC ¶61,298 (June 25, 1979).

The parties opposing the inclusion of Grand Gulf Unit No. 2 in the automatic adjustment clause argue that Grand Gulf Unit No. 2 may never be built, and it is premature to include the second unit in the automatic adjustment clause at this time. The parties argue that to have the automatic adjustment clause cover Grand Gulf Unit No. 2 would give MSE *carte blanche* to build Grand Gulf Unit No. 2 without any meaningful regulatory oversight. They also argue that MSE has shown no real need at this time for having the automatic adjustment clause cover Unit No. 2. In addition they claim that the FPC letter order of December 18, 1964 and the order on rehearing in *Tucson Electric, supra,* do not support MSE's position.

MSE witness Lupberger testified that construction of Grand Gulf Unit No. 2 was suspended in 1979 pending completion of Grand Gulf Unit No. 1, and that MSE initiated a low level of construction in 1982 to preserve the site (Ex. 1, pp. 17-18; Tr. 217, 343). The cost and completion date of Grand Gulf Unit No. 2 depend on the completion date of Grand Gulf Unit No. 1 (*Id;* Ex. 61, p. 1; Tr. 340, 346). The Middle South system has not reached a firm decision that it will commence construction of Grand Gulf Unit No. 2 upon completion of Grand Gulf Unit No. 1 (Tr. 346-7), and it is possible it may not proceed with construction (Tr. 347). According to Mr. Lupberger the estimated cost of Grand Gulf Unit No. 2 is 2.5 billion dollars (Tr. 340). According to MSE witness Perl, the estimate was 2.71 billion dollars (Ex. 89, p. 3), but was recently reduced to 2.56 billion (Tr. 1449). 600 million dollars have already been spent on Unit No. 2 (Tr. 343).

Like Mr. Lupberger, Dr. Perl testified that MSE has not decided whether to complete construction of Grand Gulf Unit No. 2 (Tr. 1450), and that his estimates with

respect to the potential benefits of Grand Gulf Unit No. 2 are more subject to uncertainty than the estimates with respect to Grand Gulf Unit No. 1 (Tr. 1774).

MSE witness Brown also stated that no decision had been made to resume construction of Grand Gulf Unit No. 2 (Tr. 594). Less than 22 percent of Grand Gulf Unit No. 2 has been completed (Tr. 581). He also stated that MSE was asking for approval of recovery of costs for a unit that MSE has not decided to build (*Id.*), that it was at least five years before Unit No. 2 could possibly go into service (Tr. 581), and that MSE is seeking approval for costs without any ceiling or cap on the total amount that may be recovered through the formula (Tr. 595), even if the costs were to increase an additional one billion dollars (*Id.*).

Earlier the Middle South system tried to obtain a low power operating license from the Nuclear Regulatory Commission ("NRC") for both Grand Gulf units. The NRC declined to issue the license for Grand Gulf Unit No. 2 because of the "time differential" between the completion dates for the two units and because construction of Grand Gulf Unit No. 2 had been extended (Tr. 846-47). Mr. Stampley explained that the NRC advised, in effect, that "we don't know what's going to happen in regulations in that time. You know, there may be some other things. And that's just too long a time span to give the license". (Tr. 847). To this date, no operating license has been issued for Grand Gulf Unit No. 2, and Middle South conceded that the NRC could refuse to license Grand Gulf Unit No. 2 (Tr. 848-52).

As noted earlier, automatic adjustment clauses are exceptions to the general rule that changes in rates be subject to the notice and review of Section 205 of the Federal Power Act. 16 U.S.C. §824d. The evidence shows that Grand Gulf Unit No. 2 may never be completed and its ultimate cost is unknown. MSE should not be given *carte*

blanche now to include most of the costs of Grand Gulf Unit No. 2 in an automatic adjustment clause when Unit No. 2 is not used or useful and may never be used or useful, and when its costs are not known and subject to review at the present time. If and when construction of Unit No. 2 nears completion and its operation is imminent, MSE at that time can come to this Commission and ask for a formula rate for Unit No. 2, just as it waited until Unit No. 1 was nearing completion and its costs were known before MSE applied to this Commission for a formula cost-of-service rate.

The two cases cited by MSE do not support its use of the automatic adjustment clause for Unit No. 2. In the first case the Federal Power Commission issued a letter order dated December 18, 1964, in which the Commission accepted for filing a power contract between Connecticut Yankee Atomic Power Company and its customers (who were also its owners). The case was not litigated. The plant was not due to go into commercial operation until 1966. The contract was to become effective on the date service was initiated (MSE's Initial Brief, p. 147). Thus Connecticut Yankee, unlike the approval MSE seeks here, could not bill its customers for charges until the plant went into service. The letter order thus provides no support for MSE's position in the instant docket that MSE should be allowed to bill customers for Grand Gulf Unit No. 2 charges five or six years before Grand Gulf Unit No. 2 goes into commercial operation, if, indeed, it ever goes into commercial operation.

The second case claimed by MSE to support its position is *Tucson Electric Power Company,* 6 FERC ¶61,195 (1979); *reh. granted in part,* 7 FERC ¶61,298 (1979). In an early order in that case the Commission considered all five phases of a five-phase contract tendered originally on December 5, 1978. Phase Three was to go into effect on May 1, 1982, and Phases Four and Five were to go into effect not later than May 31, 1985. 6 FERC p. 61,506.

The Commission rejected Phases Three, Four and Five for filing because the Commission concluded that waiver of the Commission's notice requirements was not appropriate for rate schedules which would not become effective until May 1, 1982, several years later. The Commission based its conclusion on its earlier ruling in *Indiana & Michigan Electric Company,* 4 FERC ¶61,068 (1978), where the Commission had accepted for filing an increase in the demand charge on July 12, 1974 which included a formula rate for computing a revised demand charge for 1978. When the applicant notified the Commission in 1978 that it was putting the formula into effect, the Commission rejected the applicant's contention that it had approved the second (formula) part of the demand charge in 1974 and in 1978 the applicant need only give notice of the 1978 rate. 4 FERC at p. 61,142. Later, the Commission granted rehearing, *Tucson Electric Power, supra,* and accepted Phases Three, Four and Five for filing, "[b]ased on the unique circumstances surrounding the arrangement between Tucson and San Diego." 7 FERC p. 61,649. I do not find the "unique circumstances" in *Tucson* applicable to the evidence in the instant case. Moreover, *Connecticut Yankee* and *Tucson Electric* are essentially irrelevant in the instant case because of Middle South's failure to demonstrate why it needs Commission approval of a cost-of-service formula for Grand Gulf Unit No. 2 at this time.

Considering the arguments of the parties and the evidence, I hold that the automatic adjustment clause in the Unit Power Sales Agreement should not apply to Grand Gulf Unit No. 2 at this time. The rejection of MSE's present request for including Grand Gulf Unit No. 2 in the automatic adjustment clause does not mean that MSE cannot request approval of a cost-of-service tariff at some future time for Unit No. 2 if and when MSE decides to resume construction of Unit No. 2 and the unit has reached a sufficiently concrete stage of completion that the Com-

mission can determine the prudency, benefits, costs, and other factors relating to that unit.

E. Limits on the Inclusion of Costs in the Cost-of-Service Formula

The fifth issue is what limits are appropriate on the discretion of MSE to include costs within the cost-of-service formula of the Unit Power Sales Agreement (Tr. 249).

In a statement by its attorney on the record (Tr. 106-107), the Louisiana Public Service Commission ("LPSC") contended that unless limits were placed on the discretion of MSE to include costs within the formula rate, improper costs may be included and recovered. However, neither the LPSC nor any other party to this proceeding filed testimony supporting this contention, and no participant briefed the issue.

The express concern voiced by the LPSC involved the increase in projected costs for Grand Gulf Unit No. 1 and the decrease in projected costs for Grand Gulf Unit No. 2 from the time MSE's direct testimony was submitted (October 1982) to the time of filing its rebuttal testimony (March 1983) (Tr. 106). The LPSC questioned whether certain costs were reallocated from Unit No. 2 to Unit No. 1 (Tr. 106-107).

The evidence shows that the increase in costs for Unit No. 1 is attributable primarily to delays in the construction of that Unit (Tr. 1446-47). Moreover, the record demonstrates that the projected decrease in the cost of Grand Gulf Unit No. 2 is explained by projected changes in timing and productivity for Unit No. 2 (Tr. 1450-53).

The amounts includible in the various components of the cost-of-service formula are governed by the FERC's Uniform System of Accounts. 18 C.F.R. Part 101-125 (1981). Only amounts recorded on the books of MSE in accordance with the Uniform System of Accounts will be recoverable under the Unit Power Sales Agreement.

These recorded costs will be audited by independent, outside auditors and the FERC's own audit staff as part of regular field audits (Ex. 62, p. 4). The FERC auditors who will periodically review the books and records of MSE will be able not only to verify that MSE's accounting practices are in compliance with the Uniform System of Accounts, but also to insure that expenses charged by MSE to purchasers are appropriate and that charges for power from Grand Gulf are properly billed in accordance with the Unit Power Sales Agreement and the Billing Format (Ex. 62, p. 4).

In *Middle South Services, Inc.*, Opinion No. 124, 16 FERC ¶61,101 (1981), involving a cost-of-service tariff, the Commission concluded that sufficient safeguards were provided by Commission audits of the costs included in the formula and by any investigations which might be instituted under Section 206 of the Federal Power Act. *Id.* p. 61,219. No additional limitations upon the inclusion of costs in the MSS formula were imposed.

In *Louisiana Public Service Comm'n v. F.E.R.C.*, 688 F.2d 357, 361, the Court upheld the Commission's ruling and noted "that the accuracy of the costs included under the formula could be verified by FERC audit, or by an investigation instituted under § 206 of the FPA."

There being no evidence or arguments on the issue by any participant aside from MSE (Initial Brief at pp. 25-27), it is held that aside from specific limits imposed in other sections of this Initial Decision, no additional limits should be placed on the discretion of MSE to include costs within the cost-of-service formula of the Unit Power Sales Agreement.

F. Return on Equity

The sixth issue is what is the appropriate rate of return on equity for MSE (Tr. 249).

Four parties addressed the question of the appropriate rate of return on common equity for use in the Unit Power Sales Agreement. The initial positions of the parties have been modified. Their final recommendations are these:

Party	*Recommendation*
MSE	16.5%
FERC Staff	16.04%
Louisiana Public Service Commission	No higher than 15.00%
Occidental Chemical Corp.	13.00—13.50%

The three witnesses who testified on rate of return, Dr. Lurito for the Louisiana Public Service Commission, Dr. Dietz for MSE, and Mr. Randall for Staff, each used a discounted cash flow analysis. In determining a fair rate of return, the Commission has expressed a preference for forward-looking market-oriented analyses, such as the discounted cash flow method. *Central Illinois Light Co.*, Opinion No. 81, 10 FERC ¶61,248 (1980); *Public Service Co. of Indiana, Inc., Opinion No. 44, 7 FERC ¶61,319 (1979); Minnesota Power & Light Co.*, Opinion No. 20, 4 FERC ¶61,116 (1978); *Minnesota Power & Light Co.*, Opinion No. 12, 3 FERC ¶61,045 (1978).

1. MSE

The Unit Power Sales Agreement includes an 18.0% rate of return on common equity. (*See* the definition of "Composite Percentage" in Unit Power Sales Agreement, Ex. 7, pp. 3-4; Ex. 5, p. 8.) However, MSE's transmittal letter of June 18, 1982 stated that "MSE will initiate service using a return of 16% on common equity" subject to the reserved right in the event of undue delay in obtaining a final order "to use prospectively in its billings, subject to refund with interest, 18% return on common equity" (Ex. 6, p. 3; Ex. 5, p. 13). Dr. Dietz, MSE's witness, recommended a 18.0% rate of return allowance

in his prepared testimony, which was served on October 15, 1982; but based on updated data available at the time of his oral testimony (March 16, 1983), Dr. Dietz "would come out at 17" percent (Tr. 492), and using the spot price of MSU common stock on the New York Stock Exchange as of the day he testified, he "would be down in the 16 range instead of the 17 range" (Tr. 493).

The starting point of Dr. Dietz' discounted cash flow (DCF) analysis was his recognition that all of MSE's common equity has been supplied by MSU, and any additional equity necessary to complete the Grand Gulf Nuclear Station will be supplied by MSU. He therefore used MSU common stock as a proxy for MSE common equity. This approach also was used by Staff's witness Randall. The Federal Energy Regulatory Commission has approved using MSU as a proxy for its subsidiaries when a DCF analysis is performed. *Middle South Services, Inc.*, Opinion No. 124, 16 FERC ¶61,101, pp. 61,219-222 (1981); *Louisiana Power & Light Co.*, Opinion No. 110, 14 FERC ¶61,075, pp. 61,132-133 (1981), *aff'g* Initial Decision, 6 FERC ¶63,031 (1979).

Dr. Dietz' determined the overall "cost" of MSU's equity capital as set by the market place. This overall cost was equal to the "weighted average" cost of (1) MSU's "retained earnings" and (2) MSU's "new issues of common stock" (Ex. 17, p. 29). The largest part of Dr. Dietz' testimony concerns his determination of the cost of the "retained earnings" portion of MSU's equity. Under discounted cash flow theory, he derived this cost from a mathematical process which determines the "present value" of the cash flow which, he believes, existing holders of MSU common stock expect to receive over a specified holding period from their purchases of MSU common stock (Ex. 17, p. 15).

The owner of MSU common stock will receive dividends over the holding period plus the proceeds from the sale

of stock at the end of the period. The "cost" is equal to the factor, expressed as a percentage, which discounts the investor's total expected return from owning and eventually selling a share of MSU common stock to a "present value," such that the present value equals the amount paid in the market place for the share of MSU common. Dr. Dietz determined that 3.5 percent was the factor necessary to maintain MSU's expected growth rate.

Before performing any calculations, Dr. Dietz estimated the future level of MSU's (1) earnings per share, (2) dividends per share, and (3) price-earnings ratio of its stock. He used a variety of published forecasts of financial services, including *Value Line, Moody's* and *Standard and Poor's*. He estimated MSU's earnings per share for 1982 to be $2.33 (which they turned out to be, Tr. 539) and earnings per share for 1983 to be $2.50. He estimated that earnings per share would increase at an annual rate of 3.5 percent.

Dr. Dietz noted that historically, "MSU seems to be trying to keep its [dividend] payout around 70% [of earnings]." He testified, "it is reasonable to assume investor dividend per share growth estimates in line with earnings growth—overall at a level consistent with a 70% payout" (Ex. 17, p. 21).

Having made these estimates, Dr. Dietz then made his calculations. The calculations are shown on Schedules 7 and 8 of Exhibit 18 and Schedules 7A and 8A of Exhibit 74. Having settled on a growth rate of 3.5 percent, the key variables in these schedules are (1) the market price of MSU common stock and (2) the assumption made with respect to the future price-earnings ratio of the stock. In Schedules 7 and 8, which were prepared prior to the filing of MSE's case-in-chief, Dr. Dietz used a purchase price of $13.50 per share as a proxy for the median market price of $13.31 per share during the preceding year (Ex. 73, p. 1). In Schedules 7A and 8A, which were included with Dr.

Dietz' rebuttal testimony, he used a market price of $14.06 per share, which was "the mid-point price for the twelve months to date." In Schedules 7 and 7A, Dr. Dietz assumed a constant price-earnings ratio over the holding periods, while in Schedules 8 and 8A, he assumed that the price-earnings ratio of MSU common would rise slowly over a ten-year period to reflect the gradual attainment of a market-to-book ratio of one.

Ultimately, Dr. Dietz gave more weight to the results shown in Schedules 8 and 8A which reflect the assumption of a rising price-earnings ratio. Currently, the price-earnings ratio is "low" (*see* Ex. 18, Schedule 5) but, as Dr. Dietz testified,

> Investors do expect utilities to earn their cost of capital in the long run. They do expect lower interest rates—and higher price-earnings ratios—in the future. I illustrate the effects of even a slow increase to book value over a ten-year period. For this purpose—relying on the historical showing that book value has grown slower than other financial measures, I have assumed book value growth at 2.5%.
>
> . . .
>
> If investors did not see such a better future they would not pay the price they do for MSU common stock.

(Ex. 17, pp. 23-4.)

The results of Schedules 7, 7A, 8 and 8A are these:

Assumed Purchase Price of MSU common	*Assumed Holding Period (Yrs.)*	*Assumed Price/Earnings Ratio*	*Cost of Retained Earnings*
$13.50	5	Constant	16.3%
$13.50	10	Constant	16.2%
$13.50	10	Improves to point where MSU Market-to-Book = 1	17.0%
$14.06	5	Constant	15.9%
$14.06	10	Constant	15.9%
$14.06	10	Improves to point where MSU Market-to-Book = 1	16.9%

Considering the results displayed in the schedules, and observing that the average yield on all Moody's Electric Utility bonds through the end of January 1983 varied between 13.20 percent and 14.71 percent, depending upon their respective ratings, Dr. Dietz concluded at the time of his rebuttal testimony that "the cost of retained earnings for MSU now is at least 16 percent" (Ex. 73, p. 2).

Dr. Dietz determined MSU's overall cost of equity capital by averaging the cost of retained earnings and the cost of new issues of common stock. Dr. Dietz believes that the cost of new issues of MSU common stock is higher than the cost of retained earnings. In the case of MSU, Dr. Dietz also believes that weighing each of the two components equally is appropriate because, "[i]ndications are that a 50-50 split is the best representative of financing expectations for the immediate future" (Ex. 17, p. 29). Assuming that the cost of new issues is at least 17 percent, the total average cost of common equity to MSU would be, according to Dr. Dietz, at least 16.5 percent, calculated in this manner: (.5) (16.0) + (.5) (17.0) = 16.5 percent.

Dr. Dietz explained that the cost difference between new issues and retained earnings

> is due to two causes: (1) the net proceeds from new issues will be less than the preissue market price by at least three to five percent, and (2) the market price [of MSU common stock] even before correcting for the adjustment in (1), is not equal to book value.

(Ex. 17, p. 24.)

With respect to the first cause, Dr. Dietz identified investment banking, legal, accounting and printing fees, plus downward market "pressure" by the sale of additional shares, as the sources. On the basis of these factors, Dr. Dietz believes that "a five percent adjustment applied to new issues only is reasonable and conservative" (Ex. 17, p. 28).

With respect to the second cause, Dr. Dietz was able to quantify the adjustment necessary to achieve a market-to-book ratio of 1 through the use of the "Constant Growth Model of Dividend Yield Plus Growth Rate." Examples of application of the model are set forth in Dr. Dietz' testimony (Ex. 17, p. 27). Assuming that in 1983, MSU common stock (1) earns $2.50 per share, (2) sells at $14.50 per share and (3) has a constant price-earnings ratio of 5.8, Dr. Dietz' constant growth (3.5 percent) model shows that the cost of new issues of common equity would be 17.84 percent. When adjusted by the 5 percent factor discussed above, the cost becomes 18.8 percent.

Assuming also that the cost of retained earnings is at least 16 percent and that the cost of new issues is at least 17 percent, in accordance with Dr. Dietz' weighting factors, the overall cost of all MSU equity capital, according to Dr. Dietz, is at least 16.5 percent.

2. Staff

Staff presented the testimony of Mr. Kirk F. Randall on the appropriate rate of return on equity to be allowed MSE in the Unit Power Sales Agreement. Mr. Randall's

testimony is in the record as Exhibit 50; his revised Table IV of Exhibit 50 and the updated data of MSU's DCF cost of common equity are in the record as Exhibit 123. Mr. Randall recommends that MSE be allowed a 16.04% rate of return on common equity. In arriving at this figure, Mr. Randall relied primarily on a discounted cash flow analysis (Ex. 50, pp. 20-23). The three components of the 16.04% figure are an estimated growth rate of MSU's dividend of 3.54%, a current dividend yield of 12.43%, and a flotation adjustment of .07%. Mr. Randall also performed several analyses as a check on his DCF analysis.

Like Dr. Dietz' analysis, Mr. Randall's analyses focused on the return on equity required by investors to invest in MSU. Mr. Randall used MSU as a proxy for MSE in determining the cost of common equity capital to MSE because MSE's market cost of common equity cannot be directly measured (Ex. 50 at p. 3) since MSE is a wholly owned subsidiary of MSU as are the other MSU operating subsidiaries.

Mr. Randall, however, did not restrict his analysis to an examination of only the business risks of MSU. Mr. Randall included in his analysis an evaluation of the risks of MSE as well. His evaluation of the risks revealed that the relationships and obligations of MSE and MSU are so intertwined as to render it impossible to distinguish MSE's risks from those of MSU (Ex. 50, p. 4). Mr. Randall based this conclusion on the fact that the entire MSU system, including MSE, is integrally related. MSE is totally dependent on MSU for its common stock financing and upon the other operating subsidiaries for revenues. Furthermore, MSE's ability to secure credit (and therefore its riskiness and cost of capital) has been significantly affected by the other operating subsidiaries' obligations to MSE. If MSE defaults with respect to its bonds or bank borrowings, MSU and its other subsidiaries are obligated to provide MSE with sufficient funds to meet its payment obligations (Ex. 50, p. 3-4).

The DCF formula used in Mr. Randall's analysis had two components: a growth factor and a dividend yield. Witness Randall estimated dividend growth through growth in book value per share. This methodology has been approved by the Commission. *Public Service Co. of Indiana,* Opinion No. 44, 7 FERC ¶61,319 *(1979)*; *New England Power Co.,* Opinion No. 158, 22 FERC ¶61,123, p. 61,188 (1983). (cont'd)

Mr. Randall testified that growth in book value per share depends on the retention of earnings ("internal growth") and the sale of new common stock ("external growth"). He derived an estimate of 4.41% for MSU's rate of growth in book value from internal reinvestment of retained earnings. This 4.41% is the product of the expected earnings retention rate for MSU of 30% (Ex. 50 at p. 21) and Mr. Randall's estimate of 14.7% that investors expect MSU to earn on common equity (Ex. 50 at p. 21). Mr. Randall considered *Value Line* projections for the period *1985-87,* as well as the historical record.

With respect to MSU's growth in book value due to external growth, Mr. Randall first determined MSU's growth from the sale of new common stock, based on a forward-looking analysis of MSU's common stock sales requirements for the period 1982-86. Mr. Randall then determined MSU's price to book ratio for the twelve months ending November 1982, to arrive at an external growth component of -0.87%.

Thus, Mr. Randall derived a growth factor of 3.54% (Ex. 123), the algebraic sum of 4.41% internal growth and -.87% external growth.

Mr. Randall then used the dividend yield of 12.16% for the study period of the 12 months ending November 1982. Mr. Randall adjusted the 12.16% figure to 12.43% to reflect quarterly compounding of dividends according to the formula in equation (E) at page 7 of Exhibit 50, using his 3.54% estimate for growth in dividends. The result was

an estimate of 15.97% (12.43% + 3.54%) for the cost of equity to MSU.

Mr. Randall performed several analyses to check the results of his DCF analysis. The first of these was a stock valuation model (Ex. 50, pp. 10-14) which described the relationship between stock prices and one or more variables which presumably affected those prices (Id. at 10). This model was used by Mr. Randall to determine the necessary return on equity for a number of average electric utilities to sell at a market-to-book ratio of one. These average electric utilities were selected by Mr. Randall on the basis of several fundamental risk criteria including: *Value Line Safety* Rankings, projected construction budgets and internal funds generation, earnings quality rankings, and percentages of electric revenues to total revenues (Ex. 51, Sch. 2). Mr. Randall estimated that the selected group of electric utilities possessed both average costs of common equity and average common equity growth rates. The result of this analysis was a cost of equity of 14.50% (Ex. 50, p. 14).

A second approach used by Mr. Randall, as a comparison with the results of his DCF analysis of the cost of equity for MSU, was to estimate the average DCF cost of equity for the electric utility industry (Id., p. 15-20). In determining this estimated cost, Mr. Randall used the same method that he used to estimate the cost of equity for MSU. The result of this approach was a dividend yield of 12.03% (adjusted for quarterly compounding), which, when added to a 2.91% growth rate, resulted in a cost of equity of 14.94% *(Id.,* pp. 19-20). Both this approach and the analysis based on the stock valuation model indicate that MSU's cost of equity is higher than the industry average.

Finally, Mr. Randall performed a fundamental analysis of MSU relative to the electric utility industry (*Id.*, pp. 25-30). After developing a set for measures and determinants of risks with which to compare MSU to a normal

range of data derived from the 100 utilities used as an industry aggregate, Mr. Randall used the results of this comparison as a source of further insight into the results of his DCF analysis (Ex. 50, pp. 25-26).

Among the features of MSU that Mr. Randall examined relative to the 100 electric utilities were: (1) common equity ratio (*Id.*, p. 26; Ex. 51, Sch. 4); (2) interest coverage (Ex. 50, p. 26; Ex. 51, Sch. 5); (3) use of short-term debt (Ex. 50, p. 27; Ex. 51, Sch. 6); (4) embedded debt costs (Ex. 50, p. 27; Ex. 51, Sch. 7); (5) earned rate of return on common equity (Ex. 50, p. 27; Ex. 51, Sch. 8); (6) earned rate of return on total capital (Ex. 50, p. 27; Ex. 51, Sch. 9); (7) ratio of AFUDC to net income (Ex. 50, p. 27; Ex. 51, Sch. 10); (8) ability to internally finance cash needs (Ex. 50, pp. 27-28; Ex. 51, Schs. 11, 12 and 13); (9) magnitude of construction program (Ex. 50, pp. 28-29; Ex. 51, Sch. 14); (10) fuel mix (Ex. 50, p. 29); and (11) payout ratio (Ex. 50, p. 30; Ex. 51, Sch. 16). Mr. Randall concluded that MSU's common stock has been considered more risky than the stock of an average utility in recent years, for the most part because of MSU's large construction program and inadequate internal cash generation (Ex. 50, p. 30).

Mr. Randall examined the question of what adjustment was necessary to the recommended return on equity to compensate MSU for the expected future costs of issuing new common equity (flotation cost). Mr. Randall analyzed the costs MSU incurred in its two most recent stock offerings. As a result of this analysis, Mr. Randall concluded that 2.731% of the amount of new equity dollars is an appropriate estimate of MSU's flotation expenses in future public common stock offerings (Ex. 50, pp. 24-25). Inasmuch as flotation costs are only incurred during the sale of new common stock, Mr. Randall calculated a flotation allowance which reflects the impact of the proportionate growth in common equity that is expected to occur, producing a flotation component of .07 percent (Id., p. 25).

Mr. Randall then added his estimate of MSU's flotation cost to his estimate of the market required return on equity. He concluded that MSE should be allowed an overall rate of return on equity of 16.04% (15.97% plus .07%). Ex. 123.

3. Louisiana Public Service Commission

Like Staff witness Randall and MSE witness Dietz, Dr. Richard J. Lurito, the rate of return witness for the Louisiana Public Service Commission (LPSC), used a discounted cash flow analysis to determine his recommended rate of return on equity for MSE. Dr. Lurito determined that 15 percent is the upper limit of the fair rate of return on equity for MSE, if one were to ignore the risk-reducing effects of the take-or-pay provisions in the Unit Power Sales Agreement and the cost-of-service tariff (Ex. 42, p. 22). However, Dr. Lurito testified that the risk-reducing effects of the tariff should be taken into account in making the rate of return determination, because these factors lower the risk to the MSU system as a whole by reducing earnings volatility. Dr. Lurito testified that the appropriate rate of return on equity for MSE, considering the lowered risk of the proposed tariff, is no more than 13.5 percent (Ex. 42, p. 25).

It its Initial Brief, LPSC states that a 15 percent return for MSE "... constitutes the ceiling of a fair range." LPSC argues that Staff witness Randall indicated that the best estimate of future conditions would be based on those conditions existing at the time of the hearing (Tr. 2101-2102). If data were used reflecting conditions at the time of the hearing, Mr. Randall's recommended rate of return on equity would be 14.94 percent.

4. Occidental Chemical Corporation

Occidental Chemical Corporation submitted no evidence on the rate of return issue; Occidental argues that a fair return on common equity for MSE would be in the range

of 13 to 13.5 percent in light of the downward trend in the cost of equity and in the inflation rate (Initial Brief, p. 66).

5. Discussion

The basic defect in the DCF analysis of LPSC's witness Lurito is his computation of the dividend yield portion of the DCF cost of common equity. Dr. Lurito used a one month average dividend yield for November 1982 of 11.21%. By using a spot yield of 11.21% in his DCF analysis, Dr. Lurito relied on one month's data to estimate a factor which varies significantly from month to month, and he departed from his general practice of computing a dividend yield based on at least twelve months of data (Ex. 122).

Staff witness Randall calculated a dividend yield for MSE using average stock prices of MSU for a 12-month period. The resulting difference is significant: while Dr. Lurito's dividend yield is 11.21 percent (Ex. 43, p. 7), Mr. Randall's is 12.16 percent (Ex. 50, p. 23).

The Commission has adopted DCF techniques which calculate the dividend yield component over a representative period of time. *New England Power Company*, Opinion No. 158, 22 FERC ¶61,123 (1983); *Connecticut Yankee Atomic Power Company;* Opinion No. 148, 20 FERC ¶61,373 (1982).

The weakness in using a "spot" dividend yield was explained by Mr. Randall while on the witness stand (Tr. 2105, 2106):

Q. Could you please explain why you are utilizing 12 months instead of a spot yield?

A. Well, during the recent time period, the last couple of years, capital costs have varied considerably and some normalization procedure would really be necessary to avoid the use of a spot cost of equity.

And really I demonstrate this on page 23 of Exhibit 50, where on the last line I state that over the 12-month period during which I made my study of MSU's cost of common equity, although my recommendation was a little over 16 percent, the spot cost of equity varied from about 14.5 to 17.5 percent over a 12-month period of time. That's a variation of three percentage points, 300 basis points.

Moreover, as Dr. Dietz recognized in his rebuttal testimony, ". . . if we use actual dividends for the past twelve months and the mid-point price over the past year the dividend yield becomes $1.67/$14.06, or 11.9 percent and the [Dr. Lurito's] calculated cost of common [becomes] 15.9 percent" [before application of his risk differentiation theories] (Ex. 73, p. 6).

When Dr. Lurito's DCF analysis is adjusted to reflect an average 12-month dividend yield, it supports a return allowance close to the allowance of 16.04 percent recommended by Mr. Randall.

Another defect in Dr. Lurito's recommendation for the cost of equity capital for MSE lies in his evaluation of MSE's risks. Dr. Lurito believes the take-or-pay features of the Unit Power Sales Agreement lowers the volatility of MSE's earnings and significantly reduces MSE's risk of equity. In calculating how much lower MSE's cost of equity is because of the take-or-pay provision, Dr. Lurito posited that the difference in risk between take-or-pay rates and fixed tariffs can be measured as the difference between the yields on newly issued AAA rated and BAA rated public utility debt. Accordingly, he adjusted downward his estimated 15.0% cost of equity to MSU by 150 basis points to 13.5% (Ex. 42, p. 25). Dr. Lurito further posited that the take-or-pay provisions neutralize the increased risk which he associated with the fact that Grand Gulf is a nuclear rather than a non-nuclear project.

Dr. Lurito did not present any support for either his downward adjustment to the cost of equity by 150 basis

points or his position that the risky nature of Grand Gulf, a nuclear project, is neturalized by the take-or-pay and cost-of-service provisions of the Unit Power Sales Agreement. Assuming *arguendo* that the take-or-pay and cost-of-service provisions do reduce the risk associated with Grand Gulf, Dr. Lurito has not shown that those provisions balance the risks associated with a nuclear generating facility or outweigh them. When there are factors present which tend to increase and decrease the risks associated with a particular company, "the weight given to these factors becomes critical to determining the appropriate return on equity." *Connecticut Yankee Atomic Power Company,* Opinion No. 148, 20 FERC ¶61,373, p. 61,767 (1982). There is no evidence weighing the different factors which Dr. Lurito perceives as affecting MSE's risks. Dr. Lurito has not supported his conclusion that the correct amount by which to downwardly adjust MSE's cost of equity is 150 basis points. There is nothing in the record which indicates that the difference in yields between AAA rated and BAA rated public utility debt is the appropriate measure of the difference in risk between take-or-pay, cost-of-service rates and fixed tariffs.

Dr. Lurito's low recommendation depends principally upon the validity of his theory that the Middle South system should be divided into separate risk bearing divisions and that MSE is a virtually riskless division because of the "take-or-pay" and "cost-of-service" features of the Unit Power Sales Agreement. According to Dr. Lurito, since the risk associated with MSE's sales under the Unit Power Sales Agreement is less than the overall risk or "average risk" associated with the Middle South system viewed as a whole, a lower rate of return on equity should be included in the Unit Power Sales Agreement (Ex. 42, pp. 22-25).

The Commission, however, has rejected Dr. Lurito's theory. He was the witness for LPSC in *Middle South Services, Inc.,* Opinion No. 124, 16 FERC ¶61,101 (1981), a

contested case involving the Middle South system power pooling agreement. Dr. Lurito's testimony in *Middle South Services* advanced the same risk differentiation theories he used in the instant case at pages 22 to 24 of his testimony (Ex. 42). In *Middle South Services* he asserted that the return on equity allowance in the pooling agreement should be reduced because the "selling companies" were riskless divisions of the Middle South system in view of the take-or-pay and cost-of-service features of the agreement's service schedules. *See* Administrative Law Judge's Initial Decision, 13 FERC ¶63,032, pp. 65,107, 65,109-110. The Commission gave no weight to Dr. Lurito's theory, stating:

> We also cannot accept Louisiana's contention that the judge erred in focusing on the entire electric operations of MSU. Investors in MSU purchase equity in the entire holding company, not just in the selling companies or in the buying companies.[15] Therefore, we do not think it appropriate to consider only the so-called minimal risk to selling companies in establishing a proper rate of return. As pointed out by the judge, this decision is in accord with recent Commission opinions.[16]

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[15]*See Louisiana Power & Light Co.*, Opinion No. 104, Docket No. ER77-533 (Phase II) (December 16, 1980), slip op. at 9.

[16]*Missouri Utilities Co.*, Opinion No. 82, Docket Nos. ER77-354 and ER78-14 (March 28, 1980), wherein we affirmed the focus of the rate of return risk analysis on the entire electric operations of a multiple service corporation; *Otter Tail Power Co.*, Opinion No. 93, Docket Nos. ER77-5 and E-8152 (August 15, 1980), wherein we geared the equity return to the company's business as a whole and stated a policy against unbundling of the various functions of the electric business of a utility and apportioning equity return commensurate with the risk of each function; *American Electric Power Service Corp.*, Opinion No. 50, Docket No. E-9408 (July 27, 1979) wherein we made an independent assessment of the cost of equity and established a single rate of return for an interconnection agreement among four subsidiary operating companies of AEP.

Middle South Services, Inc., Opinion No. 124, 16 FERC ¶61,101, pp. 61,221-2 (1981).

The Commission's refusal "to inquire into differential risks" so as "to avoid further complication of the already intricate inquiry into the Company's [Minnesota Power & Light Company] allocation of costs among classes of customers" was also affirmed by U.S. Court of Appeals for the District of Columbia in *Cities of Aitkin v. F.E.R.C.*, 704 F.2d 1254, 1256 (D.C. Cir. 1982).

Based on the foregoing analysis Dr. Lurito's recommendation of a 13.5 percent return on equity for MSE must be rejected.

Dr. Dietz's analysis also has some flaws. The basic defect is his failure to consider the cost of MSU's embedded common equity in determining MSU's total cost of common equity. Dr. Dietz distinguishes between the new equity capital acquired through retained earnings and new equity capital acquired through common stock sales. For each of these he calculates a different cost. For the portion of new common equity represented by retained earnings, Dr. Dietz calculates a 16.2% cost, and for the portion of new common equity represented by annual common stock sales, he calculates an 18.8% cost (Ex. 17, p. 29). Dr. Dietz then uses these two different costs to determine the overall cost of common equity to MSU. Stating that MSU expects to add to its common equity in the near future 50% through retained earnings, and 50% through external equity sales (*Id.;* Tr. 485), Dr. Dietz calculates the weighted average cost of common equity to MSU as at least 17.5% (Ex. 17, p. 29).

While Dr. Dietz may have accurately calculated a 16.2% cost for new common equity, he failed to account accurately for MSU's embedded common equity relative to new equity. Thus Dr. Dietz estimates that MSU's total common equity balance is approximately three billion dollars (Tr. 484). Dr. Dietz also estimates that MSU will raise ap-

proximately $400 million dollars in common stock in 1983 which represents approximately 80% of total additions expected through common equity (Tr. 485). This means that MSU will raise the other 20%, or $100 million through retained earnings, for a total of $500 million incremental common equity. Assuming *arguendo* that his cost estimates are correct, Mr. Dietz has calculated a rate of return which only applies to 17% of MSU's total common equity, *i.e.*, the $500 million. He has ignored the $3 billion already in place.

There is another problem with Dr. Dietz's determination of the cost of new issues and retained earnings, which can be seen by comparing his methodology with Mr. Randall's methodology. Mr. Randall used one underlying method, a DCF analysis, to determine the cost of both new issues and retained earnings. He then added a .07 percent flotation adjustment to his result to reflect additional costs associated with new issues. Dr. Dietz, however, uses two different methods to determine the cost of new issues and retained earnings (Ex. 17, pp. 22-29).

By using different methods to measure MSU's cost of retained earnings and the cost of new common stock, Dr. Dietz is being inconsistent because, as Mr. Randall pointed out, "the expected returns from MSU's common stock are the same for [all] investors" (Ex. 50, p. 34). Furthermore, the use of the earnings/price ratio is an inappropriate measure of any cost of equity, be it retained earnings or new common stock, especially when a company's price/book ratio is different from one (as was MSU's at the time of Dr. Dietz's analysis). *See, e.g., Public Service Company of Indiana, Inc.,* Opinion No. 44, 7 FERC ¶61,319, p. 61,709 (1979); *Union Electric Company,* Opinion No. 94, 12 FERC ¶61,239, p. 61,584 (1980); and *Union Electric Company and Missouri Edison Company,* Initial Decision, 21 FERC ¶63,080 (1982).

As noted earlier, Occidental did not present a witness on the issue of rate of return on common equity. Instead, it argues that "the record in this proceeding established by Middle South's own testimony" supports "a return on common equity in the range of 13 to 13.5%" (Occidental Initial Brief, p. 66).

This argument depends on Occidental's interpretation of Dr. Dietz' rate of return methodology. Occidental would have one believe that Dr. Dietz simply established a correlation between the nation's inflation rate and returns on equity for electric utilities. Thus, according to Occidental's rendition of Dr. Dietz' testimony, as inflation goes up, returns go up simultaneously, and vice versa. Accordingly, Occidental draws a conclusion that a particular inflation rate was "used to justify" Dr. Dietz' proposed rate of return and that the inflation rate is "now less than half" such level.

However, Dr. Dietz's methodology (or Mr. Randall's) does not depend on any single inflation rate or on establishing a trend between rates of return and inflation. That is apparent from Dr. Dietz's testimony and exhibits. As background for his methodology, Dr. Dietz has identified inflation as one of the major underlying forces which have over many years forced up utilities' costs of equity and borrowed money. While recognizing at the time of the hearing that "the inflation rate is down, that interest rates are down, that the prices of stocks are up somewhat over last year," Dr. Dietz also stated (Tr. 489-490):

> The scenario as I see it, however, and we have to say this humbly—Since there are many scenarios, no one knows exactly what will happen. But I think the scenario that I'm talking about—I have been reading Merrill Lynch, Goldman Sachs, Data Resources and others. I think there is general agreement that we're going to have somewhat lower inflation and somewhat

> lower interest rates, maybe down another half or three-quarters of a percent this year.
>
> And then as we move up in employment, as we move up to fuller capacity, as we begin to have to have some tighter money and control on the money supply, then we will start moving toward higher interest rates and higher inflation and higher capital costs, probably in the 1984 to '85 period.
>
> So we have here a window in which many people are going into equity issues, to bond issues, and as we begin to have more and more people coming into the capital market, I expect interest rates to rise somewhat, and I think they will be higher in 1984 on the average than they are today.

The Louisiana Public Service Commission, in arguing that 15 percent is the upper limit of the fair rate of return on equity, states in its Initial Brief (p. 54) that Dr. Dietz on cross-examination "conceded that his approaches, using updated data, would produce a 15.1 or 15.4 per cent investor return requirement for MSE" citing Tr. 541-42, 540 (LPSC Initial Brief, p. 54). However, Dr. Dietz did not make such a concession. Rather he was asked to verify mathematical computations using his rate of return equations if he used a spot market price of $15.50 for MSU common equity. Dr. Dietz's rate of return analysis does not use a spot price such as that used by Dr. Lurito. Instead, he employed the "mid-point" of the trading range of MSU common equity "over the last year" (Ex. 17, p. 22).

The Louisiana Commission makes a similar argument with respect to answers of Staff witness Randall to cross examination questions. But Mr. Randall's testimony during cross examination does not support the statement that "[i]f data were used reflecting conditions at the time of the hearing, Mr. Randall's recommended rate of return on equity would be 14.94 percent" (LPSC Initial Brief, p. 53).

Mr. Randall was asked by counsel for the Louisiana Commission to determine MSU's dividend yield based on the market price of MSU's stock on March 30, 1983 (Tr. 2101). Then counsel asked Mr. Randall to use that dividend yield of 11.06% in his DCF formula. Mr. Randall obliged, adding this dividend yield of 11.06% (adjusted to 11.33% by Mr. Randall to reflect quarterly compounding) to his growth rate of 3.54% plus a .07% flotation adjustment. As a result Mr. Randall arrived at a cost of equity of 14.94%.

The computations made by Mr. Randall during the hearing, at the behest of counsel for the Louisiana Commission, were based on the one-day "spot" dividend yield supplied by counsel. On re-direct, however, it was established that Mr. Randall does not advocate the use of a "spot" yield and that his 16.04% recommended rate of return on equity is based on a DCF analysis incorporating a dividend yield component calculated using average stock prices for a 12-month period (Tr. 2105-06).

To summarize: Occidental's recommended return on common equity in the range of 13 to 13.5 percent for MSE is rejected for a lack of evidentiary and legal support. The Louisiana Commission's argument that the return on common equity should not exceed 15 percent is similarly rejected. Dr. Lorito's recommendation for a 13.5 percent rate of return on equity for MSE is rejected. As noted, Dr. Lorito's cost of common equity would have been 15.9 percent had he used actual dividends for 12 months and the mid-point price (Ex. 73, p. 6). MSE's recommended cost of equity of 16.5 percent must be lowered because of some of the errors in Dr. Dietz' computation, which have been previously discussed.

The evidence indicates that a reasonable rate of return on equity for MSE falls in a zone between 15.9 percent on the low side and 16.2 percent on the high side. It appears from the evidence that Staff's recommended rate

of return of 16.04 percent most nearly comports with the standards set forth in *Bluefield Water Works Improvement Co. v. Public Service Commission,* 262 U.S. *679,692-3* (1923):

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Considering the evidence, the law, and the arguments of the parties, it is held that the rate of return for MSE to be used in the Unit Power Sales Agreement is 16.04 percent.

G. Depreciation

The seventh issue is what is the appropriate method and life for determining the depreciation expense for MSE (Tr. 249).

Staff is the only party taking issue with MSE's depreciation calculation. Staff and MSE differ on (1) the length of the initial period during which the units-of-production method is to be used, and (2) MSE's use of an Equal Life Group ("ELG") method rather than a remaining life method after the end of the initial period.

The Unit Power Sales Agreement provides for recovery by MSE of "depreciation accrued at a rate at least sufficient to fully amortize the non-salvageable plant investment, including the cost of removal of interim retirements, over the estimated then remaining useful life of the unit" (Ex. 7, p. 3).

MSE witnesses Brown and Faust explained how depreciation expense is reflected in the Unit Power Sales Agreement, how the depreciation expense was determined in accordance with the Agreement, and how that expense would be reflected in monthly bills prepared using the Billing Format (Ex. 5, pp. 5, 6, 9, 10-11; Ex. 7; Ex. 8, Sch. A; Ex. 9; Ex. 65).

MSE proposes to calculate depreciation by the units-of-production depreciation method during the initial period of operation of Grand Gulf. This method determines depreciation per kilowatt-hour (kWh) by taking the sum of the depreciable plant balances plus the provision for cost of removal of interim retirements and dividing that sum by the total estimated kWh to be generated by the unit over its service life. Depreciation per kWh is then multiplied by the net kWh generated each period to determine the amount of depreciation expense during that period (Ex. 5, p. 10; Ex. 8, Sch. A).

MSE wants to use the units-of-production method to reduce the charges under the Unit Power Sales Agreement during the first few years of operation of the Grand Gulf plant, before operation of the plant stabilizes (Tr. 319). If the availability factor for Grand Gulf during the initial shakedown period is lower than its expected lifetime average, the units-of-production method will help reduce the impact of rate increases needed to compensate for the costs of power from Grand Gulf during that period, and the method will spread the costs of power from Grand Gulf more equitably among customers receiving the benefits of such power.

Under the units-of-production depreciation provision, the total estimated kilowatt-hours are determined by applying an assumed 70% capacity factor over a 40-year service life and an 1,125 megawatt net generating capacity to the investment in each unit, plus provision for cost of removal of interim retirements. MSE states in its Initial Brief (p. 52) that, based on a capital cost of $2,551.5 million (MSE's 90% share), the depreciation expense to be used initially for Grand Gulf Unit No. 1 would be $0.01224 per kWh. (When MSE's prepared direct testimony was filed, the estimated depreciation charge, using the units-of-production method, was $0.01022 per kWh (Ex. 5, p. 11); the increased charge reflects the increase in the projected investment in Grand Gulf Unit No. 1 referenced in Mr. Lupberger's rebuttal testimony (Ex. 61, p. 1).) The factor of $0.01224, states MSE (Initial Brief, p. 52) would produce produce a depreciation charge of $66.4 million for the first twelve months of operation at an estimated 55 percent capacity factor compared to a charge of $84.5 million under the conventional straight-line method. Thus, depreciation in the initial stages of the plant's operation, when the unit's capacity factor is expected to be at its lowest, would reflect the actual use of the plant (Ex. 9, pp. 9-10).

As noted, MSE proposes to apply the units-of-production method of depreciation until operation of Grand Gulf stabilizes (Ex. 5, pp. 10-11; Ex. 9, pp. 9-10; Ex. 16, p. 13). This initial shakedown period is expected to extend for two to three years after Grand Gulf commences commercial operation, but the period during which MSE would use the units-of-production method would not exceed five years (Tr. 319-320).

The FERC Staff witness stated that the units-of-production method is difficult to implement, and therefore its use should not extend more than 12 months after the date of commercial operation (Ex. 52, p. 10). In support of this position, Staff witness Lenart quoted from a 1943-1944

report of a Committee of the National Association of Regulatory Utility Commissioners (NARUC) (Ex. 52, pp. 7-10). The criticisms of the units-of-production method contained in the report, however, have little applicability to the method to be adopted in this case (Ex. 65, pp. 5-6).

While it is true, as the report states (Ex. 52, p. 8), that application of the units-of-production method requires estimates both as to service life of the property and intensity of use (rather than a service life estimate only), it is this aspect of the method that makes its use appropriate during the initial period of operation of the Grand Gulf Unit No. 1.

During the initial shakedown period, the production output of a nuclear unit tends to fluctuate, and a unit may be shut down for certain periods. Under a conventional straight-line method, customers who use relatively fewer kilowatt-hours of energy per year from a unit during its initial shakedown period would pay an annual depreciation charge disproportionately larger than that paid by customers in a later period, who use a far greater amount of such energy. The units-of-production method corrects this effect. By allocating plant investment costs on the basis of actual use of the assets, the units-of-production method provides equitable treatment to the customers of the utility (Ex. 9, p. 10).

Moreover, there is no difficulty here in ascertaining a production unit that is like each other production unit. Grand Gulf will produce base power, not dump power or peaking power (Ex. 65, p. 6). Contrary to the concerns voiced in the NARUC committee report (Ex. 52, pp. 7-8), the kilowatt hours produced by the plant are essentially equivalent, regardless of when they are produced.

It is held that the units-of-production method of determining depreciation expense based on a 40-year service life and 70% capacity factor is appropriate for the initial shakedown Grand Gulf Unit No. 1, but in no event shall

use of the units-of-production method for Grand Gulf Unit No. 1 exceed five years.

The second depreciation controversy concerns the method of calculating depreciation expense over the remaining life of each unit after the initial shakedown period has been completed. MSE proposed that the equal life group (ELG), or unit summation, method be used to give effect to differences in the occurrence of retirements from, or additions to, plant. Under the MSE method, plant components are segregated on the basis of their expected service lives, and the investment in each group is amortized over its assigned life (Ex. 9, pp. 5-7). Based on a projected service life of 40 years, the annual depreciation rate, including provision for the cost of removal of interim retirements, is estimated by MSE to be 3.31%.

After the initial shakedown period Staff argues for a straight-line remaining life method that would charge a like amount ratably each year over the estimated service life, without regard to difference in the magnitude and timing of plant retirements and additions (Ex. 52, pp. 10-12).

Staff initially took issue with Grand Gulf's service life, claiming that depreciation expense should be calculated on the basis of a 32-year life. However, the design lifetime of each Grand Gulf unit is 40 years, and MSE expects that a full-power operating license, when issued, will be for a term of 40 years from the date of issuance (Ex. 65, p. 2). Staff has apparently withdrawn its objection, inasmuch as Staff witness Lenart adopted a 40-year operating life in his Exhibit 100 as a result of MSE's rebuttal testimony (Tr. 2732).

Similarly, the Mississippi Public Service Commission withdrew its only objection to MSE's depreciation expense concerning the application of the ten percent negative net salvage value. The Mississippi Commission acknowledged

on the record that it no longer objected to or took issue with MSE's depreciation expense (Tr. 109).

Staff's criticisms of the ELG method are not persuasive. While Staff cites the NARUC committee report to suggest that a distortion of depreciation accruals may occur as a result of variation in growth of utility plant (Ex. 52, p. 11), the record establishes that any such variation related to Grand Gulf should not affect the annual depreciation accruals significantly (Ex. 65, pp. 6-7). Moreover, the availability of detailed records, over which Staff express concern, is not a problem in applying the ELG method to Grand Gulf (Ex. 65, p. 7).

Staff also attacks MSE's use of the ELG method on the ground that MSE has taken a simple life-span forecast and called it ELG (Staff Initial Brief, p. 41). According to Staff, the requirements for ELG are: (1) identification of properties with the same service lives (vintaging), and (2) accumulated depreciation identified with each vintage (Staff Initial Brief, p. 42). However, MSE's proposal satisfies these requirements. As the record demonstrates, under MSE's application of the ELG method, plant components are segregated on the basis of their expected service lives, and the investment in each group is amortized over its assigned life (Ex. 9, pp. 5-7).

Another of Staff's difficulties with MSE's approach appears to be based on the fact that MSE would use data from reactors other than those it operates in applying the ELG method (Staff Initial Brief, p. 43). But Staff offers no reason why the use of such data is inappropriate. Retirements of plant components during the life of a plant are likely to be similar among plants of a similar size and type regardless of their ownership.

For these reasons, MSE's use of the equal life group method is approved for Grand Gulf Unit No. 1 after the initial shakedown period.

H. Decommissioning Expense

There are three main issues with respect to the nuclear plant decommissioning expense (Tr. 249):

A. What is the appropriate amount for the total expense?

B. What is the appropriate annual amount to be included in MSE's cost-of-service?

C. Should the funds for decommissioning be accrued in an internal or external sinking fund?

Mr. Aitkins testified for MSE regarding the appropriate method for decommissioning Grand Gulf and the estimated cost of decommissioning (Ex. 11; Ex. 67). MSE's testimony regarding recovery of decommissioning expenses was presented by Messrs. Faust, Brown and Utley (Ex. 9; Ex. 62; Ex. 64; Ex. 71).

Based on studies of the estimated costs of decommissioning other large nuclear-fueled generating stations, MSE estimates that the cost of immediate dismantlement of each Grand Gulf unit, the least costly method of decommissioning (Ex. 12, p. 20; Ex. 11, pp. 3-9), will be $93.3 million (in 1981 dollars), calculated as follows (Ex. 12, App. A):

Category	*(Millions) 1981 $*
Radioactive waste disposal	
Utilities	10.9
Special Tools and Equipment	14.800
License Fees	2.630
Project Engineering/Management Staff	0.051
Field Decommissioning Staff	6.400
Miscellaneous Supplies (protective clothing, decontaminated chemicals)	13.400
Specialty Contractors	2.455
Facility Demolition (for decontaminated and noncontaminated structures)	0.460
Temporary Construction Facilities (lockers, staging areas)	17.140
Nuclear Insurance	0.357
	1.020
Subtotal	
Local Property Taxes during the 5 years of Dismantling	69.613
	4.996
Total cost without contingency	
25% Contingency	74.609
	18.653
Total Cost	
	93.262

Using an estimated 40-year service life and MSE's 90 percent ownership of each unit, MSE proposes initially to include approximately $324,000 annually for decommissioning expense in its cost-of-service of Grand Gulf Unit No. 1, plus earnings on accrued decommissioning expense based on MSE's composite cost of capital, net of income taxes (Ex. 9, pp. 10-13; Ex. 10; Ex. 62, p. 3). This amount is based on the assumptions that a sinking fund provision is determined based on after-tax earnings of 8% for forty years, that the funds are to be used internally to reduce amounts that otherwise must be financed, that MSE's rate base will be reduced by accrued decommissioning expense,

that inflation is to be recognized as it occurs, and that the tax effect has been normalized (Ex. 6, p. 6).

No party took issue with MSE's use of the immediate dismantlement method to estimate decommissioning costs. MSE's use of the least costly method to estimate decommissioning expense is supported by Commission precedent. *Connecticut Light & Power Co.,* Opinion No. 103, 13 FERC ¶61,155, p. 61,332 (1980). MSE's use of the immediate dismantlement method to estimate decommissioning costs is approved.

1. Total Decommissioning Expense

Three issues are raised concerning MSE's estimate of total decommissioning expense. The FERC Staff (Ex. 52, p. 4) and the Mississippi Public Service Commission (Ex. 44, pp. 11-12) argue that inclusion of an allowance for property taxes payable during the dismantlement period is inappropriate because the amount is speculative and uncertain. In addition, the Mississippi Commission proposes that the energy cost of decommissioning be reduced by $9.49 million, and that the contingency allowance be reduced from 25 percent ($18.65 million) to 10 percent ($12.64 million) (Ex. 44, pp. 13-14). No other parties have taken positions on this issue.

a. Property Taxes

The record supports the inclusion in decommissioning estimates of an allowance for property taxes payable during the dismantlement period. Contrary to claims of Staff and the Mississippi Commission, the estimate of property taxes is not speculative. Current Mississippi tax law provides for payment of *ad valorem* taxes on any structural improvements on land. The Mississippi Tax Commission currently is charging *ad valorem* taxes on a pipeline, retired in place, based on 20 percent of its original cost. MP&L is paying taxes on retired substations, based on the value of the buildings, fences and equipment on the

substation site (Ex. 65, pp. 10-11). Experimental nuclear plants in other states, including South Carolina, Pennsylvania, Michigan and Minnesota have been taxed during periods of idleness while awaiting to be decommissioned (Tr. 619-621).

Staff's reliance in its brief on NRC Report NUREG/CR-0672, Vol. 1 (Battelle)(Ex. 141, pp. 4-10 and 4-11) to support the exclusion of property taxes is misplaced. That report supports MSE's position; it states:

> A factor that could have considerable influence on the choice of mode and time frame for decommissioning is the way that the facility is viewed by the local taxing authorities for property tax purposes. For example, it is possible that the plant in safe storage or entombment could be taxed at one of the following values: (1) an operating plant, (2) unimproved land, or (3), the land and structures minus the expected additional decommissioning costs (since the retired plant is a negative asset). The first alternative (which is unlikely) would force immediate dismantlement of the plant, since the accumulated tax costs would, in a few years, exceed the cost of dismantlement. The third approach would reduce the taxes to a very nominal amount, since the additional decommissioning costs could exceed the value of the land and structures. In practice, the tax rate will be negotiated between the local tax assessor and the plant owner. It will likely be based on a combination of the second and third situations given above, with the land outside the exclusion area assessed at a value comparable with adjacent similar property and the property within the exclusion area assessed at essentially zero value. Since the outer area of the site may be unrestricted in use once the reactor has been decommissioned, it may be put to productive use to pay its property taxes.

There is no reason to expect that MSE will not have to pay property taxes during decommissioning of Grand Gulf (Ex. 65, pp. 10-12). In the Grand Gulf Decommissioning Study it was assumed that the taxes would be based on 10 percent of the original value of the plant rather than the 20 percent factor the Tax Commission is charging the pipeline company (Ex. 65, p. 11). MSE's estimate of property tax expense appears to be reasonable.

The decommissioning cost study will be updated periodically in future years (Ex. 65, p. 12). Any updated study will take into account changes in tax rates or tax policies which may arise. However, given the present assessment of *ad valorem* taxes on retired property in Mississippi and the likelihood that Grand Gulf will continue to be taxed after retirement and throughout the decommissioning period (Ex. 65, p. 12), denial of an allowance for property taxes at this time would be inequitable and unfair to consumers receiving service at the end of the service life of Grand Gulf.

b. Energy Costs

The Mississippi Commission's proposed reduction of the energy cost for decommissioning of Grand Gulf Unit No. 1, which would reduce decommissioning expense by $9.49 million, is based on the assumed availability of electric energy from Grand Gulf Unit No. 2 at 19.16 mills/kWh (Ex. 44, p. 10). As noted, Unit No. 2 may never be built. In addition, the Mississippi Commission's proposal overlooks the fact that MSE is contractually obligated to make the power from each unit available to those purchasers who have obligated themselves to pay the fixed and operating costs of each unit. Therefore, the power from Unit No. 2 would be available only to the purchasers of that power and would not be available for decommissioning of Unit No. 1 (Ex. 67, p. 2).

The Mississippi Commission's proposed reduction of the energy cost would require the retail customers 30 to 40

years hence to pay higher utility costs because the customers who paid for the energy from Unit No. 1 over its life would not have provided adequately for the electricity that will be necessary to decommission that unit (Ex. 67, p. 2).

The energy cost estimate contained in MSE's decommissioning expense was based on the present day cost of power used in the construction of Unit No. 1 (Tr. 679, 681). Inasmuch as the entire estimate for decommissioning is in 1981 dollars, this is a reasonable basis for estimating the cost of energy to be used in the decommissioning of Unit No. 1.

The Mississippi Commission questioned the assumption that 33 percent more "fuel oil" would be required for dismantlement of Grand Gulf than that required in dismantlement of a slightly smaller plant and reflected in decommissioning studies prepared by Battelle Pacific Northwest Laboratories (Battelle)(Ex. 44, pp. 10-11). However, the Mississippi Commission has incorrectly assumed that "fuel oil" is the fuel that would be used to make steam for use in the decommissioning process. As explained by MSE, the difference between the energy costs of decommissioning in the Battelle Study and MSE's proposed energy costs is based on the fact that Grand Gulf is eight percent larger than the plant in the Battelle Study and the fact that the energy supply for the Grand Gulf auxiliary boiler will be electricity rather than "fuel oil" (Ex. 67, pp. 2-3).

Based on the foregoing discussion, I reject the Mississippi Commission's proposed reduction of MSE's proposed energy costs for decommissioning Grand Gulf Unit No. 1.

c. Contingency Allowance

A further issue affecting total decommissioning costs concerns the proper contingency allowance. While all parties agree that the estimate of nuclear plant decommis-

sioning costs to be experienced forty years in the future is subject to substantial uncertainty, the Mississippi Commission argues that a 10 percent contingency allowance is appropriate rather than the 25 percent allowance proposed by MSE (Ex. 44, pp. 13-14).

MSE demonstrated on the record that a 25 percent contingency allowance is conservative (Ex. 67, pp. 3-4). MSE's study was based on a Battelle study (Document NUREG 0672), an accepted document throughout the industry for identification of the costs of decommissioning. An earlier Battelle study was relied upon by the Commission in *Connecticut Yankee Atomic Power Company,* Docket No. ER78-360, Initial Decision, 10 FERC ¶63,018 (1980), *aff'd in part,* Opinion No. 102, 13 FERC ¶61,154 (1980). NUREG 0672 provided a 25 percent contingency allowance (Tr. 670). Moreover, this figure may be low (Tr. 671). MSE's contingency allowance falls in the lower end of a range which varies from twenty to fifty percent (Tr. 676-677). For these reasons, the use of a 25 percent contingency in MSE's initial estimate of decommissioning costs will be allowed.

Based on the foregoing discussion, it is held that MSE's decommissioning costs in the amount of $93.3 million is supported by the evidence and is approved.

2. Annual Amount of Decommissioning Expense

Based on a 40-year service life for Grand Gulf Unit No. 1 and estimated decommissioning costs for that unit of $93.3 million (in 1981 dollars), MSE initially proposed to include $2.1 million annually in its cost-of-service to compensate it for its 90 percent share of the decommissioning costs (Ex. 6, p. 6). MSE arrived at the $2.1 million figure by multiplying the total amount it claims it needs, 93.3 million dollars (Ex. 12, Appendix A), by its percentage ownership in Grand Gulf Unit No. 1 (90%) (Ex. 22, p. 13; Ex. 49, p. 2), and dividing by the expected service life of the plant, 40 years (Ex. 6, pp. 5-6).

Later in the hearing, to mitigate the immediate impact of the cost of power from Grand Gulf, MSE, through its witness Faust, proposed to use an internal sinking fund for accumulation of decommissioning expenses. Under this approach, MSE would collect $324,000 annually, plus earnings on the accumulated balance in the sinking fund billed at the composite cost of capital, net of current income taxes, for its 90 percent share of the decommissioning cost (Ex. 9, pp. 11-13; Ex. 10; Ex. 62, p. 3; Ex. 64). During the first five years, MSE would charge $360,000 in its cost of service annually and then review the fund's progress (Ex. 9, pp. 10-13; Ex. 10). MSE recognizes that it might be necessary to change this annual charge over the life of the plant to account for inflation and changes in technology, economic conditions and regulatory requirements (Ex. 9, pp. 10-13).

Staff witness Lenart originally proposed an annual funding requirement of approximately $1,663,000 over a life of 32 years for the entire Grand Gulf Unit No. 1 plant (Ex. 52, pp. 5-6; Ex. 54). The $1,663,000 figure was based on Mr. Lenart's total decommissioning estimate of $87.3 million which excluded an allowance for property taxes. (As noted earlier, we have approved MSE's $93.3 million figure which includes an allowance for property taxes.) After Mr. Lenart learned that MSE expected to obtain a 40-year operating license (Ex. 65, p. 2), he redeveloped his fund over a life of 40 years and obtained an annual funding requirement of $1,158,000 for Grand Gulf Unit No. 1 (Ex. 100).

Because of the requirement in the next section of this Initial Decision that an external sinking fund must be established for nuclear decommissioning expenses for Grand Gulf, MSE's proposal for an internal sinking fund must be rejected. The Staff approach expounded by Mr. Lenart is reasonable. However, the calculation must be based upon a decommissioning estimate of $93,262,000 rather than Mr. Lenart's $87,300,000. Using Mr. Lenart methodology (*see*

Ex. 52, pp. 4-6; Ex. 54; Ex. 100), I hold that MSE's cost of service shall include $1,236,876 annually for decommissioning expenses.

Staff urges the Commission to order periodic review of the decommissioning fund as part of a Section 205 filing which MSE should be ordered to make not less often than every fifth year. The suggestion of Staff is not adopted. (*See* the discussion, *infra*, concerning the issue of whether the Unit Power Sales Agreement should be refiled with this Commission every five years.) The Commission can periodically review the adequacy and the sufficiency of decommissioning expenses at any time and if necessary begin a proceeding under Section 206 of the Federal Power Act to correct any deficiencies or deal with other problems.

3. External Sinking Fund

The FERC Staff and the Mississippi Public Service Commission propose that the nuclear plant decommissioning expense be accumulated in an external sinking fund. Staff urges that the external sinking fund be placed under control of a trustee independent of the management of MSE and Middle South Utilities, Inc. MSE has proposed that it be authorized to use the decommissioning funds internally for construction of Grand Gulf Unit No. 2 until that unit becomes commercial, at which time MSE would be willing to fund the accumulated provision externally, if the Commission so desired.

MSE argues that FERC has not required external funding in connection with funds collected to cover payment of future decommissioning costs. MSE states that in those instances where a separate decommissioning fund under control of a third party has been authorized, the filing utility has requested approval of such a fund. MSE argues that in the only case in which the Commission reached the issue on the merits, an external sinking fund was rejected. *Connecticut Yankee Atomic Power Company,* Opinion No. 102, 13 FERC ¶61,154, p. 61,329 (1980). MSE notes, how-

ever, that the Commission accepted a settlement in *Maine Yankee Atomic Power Company*, 20 FERC ¶61,141 (1982), in which an external trust fund was agreed upon by all parties.

In addition, MSE argues that establishment of an external sinking fund will increase the need of MSE to resort to external sources of capital to complete construction of Grand Gulf Unit No. 2, thereby increasing the cost of that plant to consumers (Ex. 62, p. 2).

MSE also takes issue with the argument of the Mississippi Commission that MSE will somehow be entitled to a tax deduction to which it would not otherwise be entitled if accruals for nuclear plant decommissioning expense are placed in an external sinking fund (Ex. 44, pp. 15, 16, 18). MSE states that despite repeated references in his prepared testimony to "IRS guidelines" requiring use of an external fund to assure a deduction of decommissioning accruals, the Mississippi Commission witness was unable to point to any published statement from the Internal Revenue Service or to any other substantial authority to that effect, and that on cross examination he admitted that his information was based simply on phone calls to the Internal Revenue Service prior to the preparation of his testimony (Tr. 2637).

MSE argues that criteria for deductibility of decommissioning costs contained in a National Regulatory Research Institute (NRRI) report, supplied by the Mississippi Commission in response to a data request on this issue, have not been agreed upon by the IRS (Tr. 301). On the contrary, under current IRS policy, deduction of decommissioning expense annually from a company's income is not allowed, and the IRS has indicated that utility contributions to a trust fund meeting the criteria discussed in the NRRI report "would probably not be tax exempt." "Assuring the Availability of Funds for Decommissioning Nu-

clear Facilities" (NUREG-0584, Rev. 3), U.S. Nuclear Regulatory Commission, March 1983 at 14-16 (*see* Ex. 142).

MSE states that it is unaware of any provision of the Internal Revenue Code or the Treasury Department regulations thereunder which might allow for exclusions or current deductions from taxable income of amounts being collected in anticipation of future nuclear plant decommissioning expenses (Ex. 71, pp. 10-21). The present IRS position on this matter is that all amounts collected as a provision for decommissioning costs are currently includible in the utility's income for Federal income tax purposes (Ex. 71, pp. 14-20). Moreover, no utilities have as yet received favorable rulings from the IRS regarding either tax exclusion of amounts collected and deposited in an external trust fund or current deductibility of payments to such funds (Ex. 71, p. 20).

Although legislation has been introduced in Congress (Ex. 71, p. 21; H.R. 2820, 98th Cong. 1st Sess., 159 Cong. Rec. H2509 (daily ed., April 28, 1983)) which would allow electric utilities to take future decommissioning expenses as a current income tax deduction to the extent allowed in cost of service for ratemaking purposes, MSE notes that no such legislation has been passed by the Congress.

I find that the arguments of MSE are not persuasive and that an external sinking fund should be established for the nuclear plant decommissioning expenses.

At present Grand Gulf Unit No. 1 is the only production facility MSE operates (Ex. 1, pp. 3-4). The only other production plant that may be owned by MSE is Grand Gulf Unit No. 2, which may never be completed. When Grand Gulf Unit No. 1 production facilities are retired there may be no other MSE facilities capable of producing revenues. Consequently, there is no assurance that the funds collected for decommissioning will be available at the end of the life of the plant. A sinking fund under the control of an independent trustee, free from any influenced

by the utility and administered separately from the utility's other assets, would assure the availability of the funds at the time of decommissioning (Ex. 52, p. 5).

Mr. Flaherty, the witness for the Mississippi Commission, testified that an external fund is necessary (1) to maintain the fund's integrity and assure funds will be available at the time MSE decommissions Grand Gulf Unit No. 1, (2) to guarantee that the funds will be used for the purpose for which they were collected, and (3) to balance the twin objectives of minimizing investment risk and maximizing investment earnings (Ex. 44, pp. 17-18).

A draft report of the U.S. Nuclear Regulatory Commission, entitled "Assuring the Availability of Funds for Decommissioning Nuclear Facilities," is in the record as Exhibit 142. The report indicates that there are three plant-specific funding alternatives, which in descending order of reliability are (1) prepayment or total deposit of funds at time of start-up, 2) external sinking fund, and (3) internal reserve. (*Id.*, pp. 11-13.) Because the estimated amount for the immediate dismantlement option proposed by MSE is $93.3 million in 1981 dollars (Ex. 12, p. 1; Ex. 10), prepayment is not a viable option. The external fund is the next most reliable method. Because it is outside the utility, it would not be vulnerable under most trust arrangements if the utility went bankrupt. The least reliable of the three alternatives is the internal reserve or fund, which depends on financing internal to the utility and thus is vulnerable to any event which undermines the utility's financial solvency. Funds earmarked for decommissioning might have to be paid instead to satisfy the claims of creditors (Ex. 142, pp. 11-13).

To support its argument for an internal fund, MSE relies heavily on *Connecticut Yankee Atomic Power Company*, Initial Decision, 10 FERC ¶63,018 (1980); *aff'd in part*, Opinion No. 102 13 FERC ¶61,154 (1980). But there are

significant differences between that case and the facts in the instant case.

In the Initial Decision in *Connecticut Yankee,* one basis for rejecting an external fund was that the company's existing bonded indebtness would be retired by 1993 and its common stock redeemed by 1998, although the plant's operating license would not expire until 2004. All of the depreciation charges collected from the rate payers after bond retirement and common stock redemption would be available for the payment of decommissioning costs. There was therefore no countervailing benefit to the public to make up for the additional cost burden resulting from the requirement for an external fund. 10 FERC p. 65,108.

In the instant docket, MSE is planning to charge its customers depreciation expense as well as decommissioning charges during the entire operating life of Grand Gulf Unit No. 1 (Ex. 9, pp. 6-7; Ex. 10). On this basis alone the facts of *Connecticut Yankee* differ from those in the instant docket. In addition, it does not appear anywhere in the *Connecticut Yankee* Decision that the company there was going to use the decommissioning monies for constructing an additional plant.

Furthermore, the Commission in its Opinion in *Connecticut Yankee,* 13 FERC ¶61,154, did not specifically reject the concept of an external fund. The Commission stated that it expressed no view on the merits of an external fund for future proceedings:

> The initial decision on this issue [of decommissioning costs] is affirmed and adopted. However, as to the judge's determination not to require a separate escrow fund, we add the following caveat. . . . *The Commission expresses no view on the merits of this question for future proceedings.*

13 FERC at p. 61,329 (emphasis added).

In *Boston Edison Company,* Opinion No. 156, 21 FERC ¶61,327, p. 61,881 (1982), a case arising after *Connecticut Yankee,* the Commission in rejecting an external fund for spent nuclear fuel stated:

> We recognize, however, that there might be future cases where a segregated trust fund approach would be appropriate because it provides assurance that a company will be financially able to pay the SNF costs at the time they are actually incurred some years in the future. There well may be a situation where the Commission would give greater weight to this safety risk argument, particularly where a utility is a single asset company[19] or where it is in poor financial condition.***
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> [19] We recently approved such an approach in a contested settlement involving Maine Yankee Atomic Power Company, a single asset company. *Maine Yankee Atomic Power Company,* Docket No. ER82-15, order issued August 3, 1982. [20 FERC ¶61,141]

Thus the Commission has indicated that it would seriously consider the use of an external fund for a single asset utility.

It is perhaps worth noting that MSE repeatedly refers to the example of the Yankee companies in support of its formula rate (Ex. 5, pp. 2-3; Ex. 6, pp. 2-3; Tr. 98-99; 563-64; MSE's Initial Brief, p. 22), but when arguing against external funding it has chosen to ignore the fact that three of the four Yankee companies have external funds. *Yankee Atomic Electric Company and Public Service Company of New Hampshire,* 12 FERC ¶61,329 (1980); *Maine Yankee Atomic Power Company,* 17 FERC ¶61,208 (1981); *Vermont Electric Power Company, Inc. and Vermont Yankee Nuclear Power Company,* 23 FERC ¶61,059 (April 15, 1983). (*See* Tr. 316,619.)

In light of the foregoing discussion, it is held that MSE shall accumulate nuclear plant decommissioning expenses in an external sinking fund under the control of a trustee independent of the management of MSE, Middle South Utilities, Inc., or any subsidiary of Middle South Utilities, Inc. The proposed trust indenture shall be filed with this Commission for approval.

I. Cash Working Capital Allowance

The next issue involves the appropriate allowance for MSE's cash working capital (Tr. 249).

Cash working capital is an item which the Commission allows in rate base to permit a company to earn a return on capital for expenditures necessary to maintain daily operations when the expenditures are made before the company recovers those expenditures through receipt of revenues.

MSE's witnesses on the working capital allowance were Messrs. Brown (Ex. 5) and Utley (Ex. 16 and Ex. 71). For purposes of determining the cash working capital allowance, MSE used FERC's traditional 45-day formula. This method assumes that cash working capital requirements can be reasonably estimated by using an amount equal to 45 days operating and maintenance (O&M) expenses or one-eighth of the annual O&M expenses, exclusive of any purchased power and fuel expense (Ex. 16, pp. 6-7).

Staff supports MSE's use of the 45-day formula.

The City of New Orleans argues in its prehearing brief that MSE should not be permitted to use the 45-day formula to determine its cash working capital allowance unless the use of the formula were justified by a "fully developed and properly prepared lead-lag study." In its post-trial brief, however, New Orleans takes no position on the issue.

The Louisiana Commission, through the testimony of its witness Louiselle, recommends that "no cash working capital allowance be reflected in the net investment used to compute the monthly charges" (Ex. 41, p. 17). Mr. Louiselle claimed that the payment receipts lag cannot exceed 30 days, and that any such lag is offset to a certain extent by expense lags (Ex. 41, p. 16).

The 45-day rule for determining cash working capital originated in *Interstate Power Co.*, 2 FPC 71, 85 (1939). Over the years this method has been found to produce reasonable results without the expense of prolonged litigation or the cost of preparing detailed lead-lag studies. *Commonwealth Edison Co.*, Opinion No. 165, 23 FERC ¶61,219, p. 61,464 (1983).

In *Carolina Power & Light Company*, Opinion No. 19, 4 FERC ¶61,107, p. 61,224 (1978), the Commission reaffirmed its preference for the 45-day formula:

> The formulary method for determining a proper working cost [sic] allowance has been approved by the Commission in numerous electric rate cases and, over the years, has been found to produce a reasonable approximation of the need for a cash working capital allowance without the impediment of extended controversy regarding the numerous components involved in a properly performed lead-lag study. As expressed in the *Public Service Commission of Indiana* case, "[t]he management of rate cases demands some concession to conventions based on sound business practice." [Footnotes omitted.]

Accordingly, the Commission stated that "We believe that the formulary method continues to be appropriate for the determination of a cash working capital allowance . . ." *Id.*, p. 61,225.

On rehearing, in Opinion No. 19-A, 6 FERC ¶61,154 (1979), the Commission again affirmed its support of the

45-day rule, but noted that the Commission Staff had been instructed to review the formulary approach and to recommend a new methodology, if necessary. The Staff's recommendations resulted in a proposed rulemaking, Calculation of Cash Working Capital Allowance for Electric Utilities, Notice of Proposed Rulemaking, Docket No. RM79-49 [*FERC Statutes and Regulations* ¶32,026] (June 7, 1979).

In Opinion No. 19-A the Commission stated:

> Pending receipt of the results thereof and the possible adoption of a revised formulary approach through rulemaking, we do not believe it would be proper to prohibit parties from submitting lead-lag studies that attempt to develop a proper working capital allowance. Consequently, our discussion of the 45-day formula in Opinion No. 19 should not be taken as a blanket prohibition of lead-lag studies. During this interim period our course will be as follows. Where a fully developed and reliable lead-lag study is available in the record, we will utilize that study to determine the working capital allowance. Where a study meeting these criteria is not available we will continue to apply the 45-day convention.

6 FERC ¶61,154, pp. 61,295-296 (footnote omitted).

In *Connecticut Yankee Atomic Power Co.*, Opinion No. 102, 13 FERC ¶61,154 (1980), involving a power sales agreement similar to that at issue in this proceeding, the Commission approved the use of the 45-day formula as it currently exists in developing a proper cash working capital allowance for a single asset generating company.

As recently as May 12, 1983, the Commission reemphasized that:

the interim procedures [outlined in Opinion No. 19-A] would be followed until, and if, a final rule is adopted.[7]

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[7] *Louisiana Power & LIght Company*, Opinion No. 110, 14 FERC ¶61,075 (1981); and *Pennsylvania Po..r Company*, Opinion No. 89, 12 FERC ¶61,049 (1980) . . .

Commonwealth Edison Co., Opinion No. 165, 23 FERC ¶61,219, p. 61,465 (1983).

While the Commission has thus indicated its willingness to consider lead-lag studies in individual cases, it has consistently maintained the presumptive validity of the 45-day rule where proponents of a lead-lag study fail to demonstrate that it is "fully developed and reliable." *Louisiana Power & Light Co.*, Opinion No. 110, 14 FERC ¶61,075, pp. 61,121-2 (1981), *aff'd per curiam sub nom. Cities of Winnfield and Vidalia, La. v. F.E.R.C.*, 683 F.2d 415 (5th Cir. 1982). In the instant case there is no lead-lag study in the record.

The contention of the City of New Orleans, that MSE should not be allowed to use the 45-day formula absent a fully developed lead-lag study, is without merit. Nothing in the Commission's pronouncements requires justifying the use of the 45-day formula through a lead-lag study. On the contrary, as the Commission itself has said,

> The 45-day formula controls unless its results are rebutted by evidence, such as a lead-lag study, of the utility's actual lag between the payment of expenses and the receipt of revenue. *Tennessee Gas Pipeline Company*, Opinion No. 769, Docket No. RP73-113 (July 9, 1976), slip op. at 38, *reh. denied* Opinion No. 769-A (May 31, 1977).

Louisiana Power & Light Co., Opinion No. 110-A, 15 FERC ¶61,297, p. 61,654, n. 1.

The Louisiana Commission notes that under the proposed Unit Power Sales Agreement there are only three

customers, LP&L, MP&L and NOPSI, and the Agreement specifically sets forth the date on which bills must be paid. If payment is delayed, interest accrues at a specified rate. The Agreement states:

> "5. Monthly bills calculated in accordance with the provisions of Section 1.3 shall be issued by MSE on the fifth working day of each month and shall be payable in immediately available funds on or before the 15th day of such month. After the 15th day, interest shall accrue on any balance due at the rate required for refunds ordered pursuant to FERC regulations under the Federal Power Act."

The Louisiana Commission argues that since the purchasing companies must pay their bills no later than the 15th day of the month after which service is rendered, the revenue lag is 30 days, and MSE witness Utley confirmed this fact (Tr. 286-87).

The Louisiana Commission also notes that pursuant to the terms of the Unit Power Sales Agreement, such items as materials and supplies and prepayments, which are typically a part of working capital, are separately included as rate base components (Tr. 275; Ex. 8, Sch. B). In addition, the company seeks a working capital allowance equal to one-eighth of the accounts for Production, Transmission, Customer Accounts, Customer Service & Informational, Sales and Administrative & General (Ex. 8, Sch. C; Tr. 288). When questioned about the accounts to which the 45-day formula would apply, Mr. Utley admitted that none of those expense items are paid by MSE before the services are in fact provided to MSE (Tr. 289). The Louisiana Commission argues that the combination of a 30-day lag in the receipt of revenues, and no "lead" in the payment of expenses, establishes that the working capital requirement is 30 days or less. Moreover, argues the Louisiana Commission, the lag in the payment of most expenses is likely to be at least 30 days (Ex. 41, p. 16).

The Louisiana Commission also notes that wages, which form a portion of the expenses contained in Schedule C of Exhibit 8, is the only item for which the lag in payment might be less than 30 days. However, argues the Louisiana Commission, any resulting cash working capital requirement will be more than offset by the working capital provided to MSE through the payment to MSE by the operating companies of the lease cost of nuclear fuel prior to payment to the lessor. Fuel payments will be made 30 days after the close of each quarter, or about 70 days after the fuel is used on average. The Louisiana Commission also argues that income taxes will be paid to MSE by the operating companies before those funds are paid to the appropriate taxing authorities.

For several reasons, the position of the Louisiana Commission, that no working capital allowance should be permitted MSE, must be rejected.

The record contains no lead-lag study, much less a fully developed and reliable one. The only record support for the LPSC's recommendation is Mr. Louiselle's statement that the payments receipts lag is offset, to a certain extent, by expense lags (Ex. 41, p. 16). The record includes no evidence with which to quantify the leads and lags expected to be experienced by MSE (Ex. 71, p. 4). To pick and choose several items that might be comprehended in a lead-lag study and simply estimate their respective receipt/payment lags, as Mr. Louiselle did, is inappropriate (Ex. 71, p. 3). Indeed, an effort to estimate an expense lag for only one category of expenses was found to constitute a fatal flaw in an otherwise salvageable lead-lag study ink *Louisiana Power & Light Co.*, Opinion No. 110, 14 FERC ¶61,075.

The fact that MSE may receive revenues for interest costs before they are paid to bondholders does not, as Mr. Louiselle contends, offset the cash working capital require-

ment nor does it justify a zero allowance here. In *Louisiana Power & Light Co.*, the Commission stated:

> In Florida Gas Transmission Company the Commission rejected the use of interest on long high-term [debt] in determining a utility's cash working capital allowance on the ground that such interest is not an operating or cost-of-service expense but a below-the-line item. The Commission reasoned that as a matter of policy these funds belonged to the utility and its shareholders so that a utility could not be expected to use them as working capital without remuneration. The same reasoning applies to funds used to pay dividends on preferred and common stock. the policy articulated in *Florida Gas* involved the application of the 45-day formula but is equally applicable to a lead-lag study.

Id. p. 61,122 (footnote omitted).

Finally, the Louisiana Public Service Commission's contention, that MSE's working capital requirement is offset by the income taxes paid to MSE by the MSU operating companies before they are paid to the taxing authorities, is similarly defective. In *Carolina Power & Light Co.*, Initial Decision, 4 FERC ¶63,015, p. 65,135 (1977), the Presiding Judge, citing *Sierra Pacific Power Co.*, 53 FPC 1795, 1801 (1975), stated:

> Even though at one time the Commission credited working capital (cash) with a percentage of income tax accruals, subsequent Federal income tax amendments altered the Commission's approach: "the accruals of current income taxes, pending their quarterly payment to the tax collector, are no longer of such substance, proportion and continuity that they can be relied upon as a source of working capital." (Citations omitted.)

On appeal, the Commission stated that the proposed use of tax accruals as a credit to cash working capital had been rejected in a number of prior cases. The Commission concluded that no reason had been shown to modify that policy. *Carolina Power & Light Co.,* Opinion No. 19, 4 FERC ¶61,107 (1978).

While the Commission did say on rehearing in Opinion No. 19-A, *Carolina Power & Light Co.,* 6 FERC ¶61,154 (1979), that an a offset to the working capital allowance determined by the 45-day rule might be considered when warranted by the facts in a particular proceeding, the record in the instant case does not contain the detailed calculations necessary to demonstrate that an offset is appropriate.

Based on the foregoing discussion, it is held that MSE shall use one-eighth of MSE's annual O&M expenses, exclusive of purchased power and fuel expense, in determining its working capital allowance.

J. Customer Service and Sales Expenses

The next issue is whether MSE's cost of service should include a provision for customer service and informational expenses and sales expenses (Tr. 250).

MSE's cost-of-service formula rate provides for recovery, *inter alia,* of customer accounts, customer service and informational, sales, and administrative and general expenses, as defined in Accounts 901-932 of the FERC's Uniform System of Accounts (Ex. 8, Sch. C).

MSE's witness Brown (Ex. 62, p. 6) testified that MSE needed to include a provision for customer service and informational expenses and sales expenses in MSE's cost-of-service formula rates.

The FERC Staff recommends that customer service and informational expenses (Accounts 907-910) and sales expenses (Accounts 911-916) be eliminated from the oper-

ating expenses and from the development of the working cash allowance under the formula rate because they relate primarily to retail sales (Ex. 49, p. 3).

I find that the Staff's position is correct and that MSE's cost-of-service formula rates should not include a provision for customer service and informational expenses and sales expenses.

The expenses in question are related more to retail customers than to wholesale customers (Ex. 49, p. 3). To provide these services and to recover the associated expenses from the MSE operating companies, which already provide these services to their retail customers, would be duplicating such services and expenses *(Id.)*.

Customer service and informational expenses are related to the cost of providing instructions or assistance to customers to encourage safe, efficient and economical use of the utility's service *(Id.)*. The operating subsidiaries do not need these kind of services, and MSE has not demonstrated that they will need them during the life of Grand Gulf Unit No. 1.

Sales expenses are related to promoting or retaining the use of utility services by present and prospective customers *(Id.)*. MSE Need not provide this service; the Unit Power Sales Agreement defines the customers for the life of the contract (Ex. 6, p. 2; Ex. 7, p. 2), and MSE does not presently expect other purchasers to appear (Tr. 554).

MSE's witness Brown conceded that under normal circumstances the expenses in question would relate primarily to retail customers and therefore that little or no expenses would occur (Ex. 62, p. 6). While Mr. Brown states that circumstances may develop where it would be appropriate MSE to incur such costs. Mr. Brown was unable to provide a convincing description of those circumstances *(Id.,* pp. 6-7; Ex. 99). When asked how those expenses might be incurred, Mr. Brown stated that sales expenses might be incurred in negotiating short-term sales of capacity and

energy in behalf of the purchasers (*Id.;* Tr. 554-5). However, even if one of the operating companies were to locate a short-term customer for Grand Gulf power, it would be the operating company's power to sell; MSE would not necessarily become involved in the transaction. The Unit Power Sales Agreement contains no provisions permitting MSE to act as agent on behalf of the operating companies to make short-term sales transactions to parties outside the MSU System (Ex. 7).

MSE attempts to support its inclusion f the disputed expenses by stating that the formula rate of Connecticut Yankee Atomic Power Company includes such expenses and that the Commission approved them in *Connecticut Yankee Atomic Power Company,* Opinion No. 102, 13 FERC ¶61,154 (1980). However, neither Opinion No. 102 nor the underlying Initial Decision, 5 FERC ¶63,004, reveal that customer services, informational and sales expenses was an issue in the *Connecticut Yankee* proceeding.

Commission precedent imposes a burden on the applicant to justify recovery of these expenses. *Arizona Public Service Company,* Opinion No. 177, 23 FERC ¶61,419, p. 61,930 (June 23, 1983). MSE has not met that burden. It is therefore held that MSE's cost-of-service formula shall not include a provision for customer service and informational expenses and sales expenses, nor shall such expenses be used in developing MSE's cash working capital allowance.

Tax Normalization

When this case began there was a question whether MSE has substantiated its claim that it has met the tax normalization requirements of the Economic Recovery Tax Act of 1981.

In its letter of June 18, 1982, to the Federal Energy Regulatory Commission, transmitting the Unit Power Sales

Agreement for filing, MSE advised the Commission that its cost-of-service rates reflect that the timing differences between book and tax, related to all property placed in service after 1980, have been fully normalized by MSE as required by Section 168 of the Internal Revenue Code, adopted as part of the Economic Recovery Tax Act of 1981 (ERTA) (Ex. 6). In addition, MSE proposed to normalize all timing differences in conformance with Commission Order Nos. 144 and 144-A [*FERC Statutes and Regulations* ¶30,254, ¶30,340] (Ex. 16, pp. 5-6).

In its Order Granting Rehearing in Part and Clarifying Prior Order, issued December 30, 1982 in this proceeding, the Commission found that

> insufficient information has been submitted to determine whether MSE's normalizing procedures are consistent with ERTA requirements . . . To permit MSE to qualify for ACRS benefits, our orders permitting the rates to be collected subject to refund will be expressly conditioned upon the proper normalization procedure being ultimately reflected in the final, approved rates.

21 FERC ¶61,393, pp. 61,976-77 (footnote omitted).

MSE's witness Utley presented testimony with regard to tax normalization (Ex. 16; Ex. 71). In response to the FERC Staff request, MSE explained the manner in which it proposes to normalize the timing differences involved, in conformance with ERTA and Order Nos. 144 and 144-A (Ex. 71, pp. 5-10). In addition, MSE submitted sample calculations showing that the accounting which it proposes to use for income taxes is based upon comprehensive interperiod income tax allocation (Ex. 72).

MSE claims that normalization will have important tax benefits. Because MSE's operating assets have not yet been placed in service, all of its plant is subject to the requirements of ERTA (Ex. 71, p. 7). For MSE to receive

the tax depreciation benefits provided under the Accelerated Cost Recovery System that ERTA established, it is necessary for MSE to receive approval from the Federal Energy Regulatory Commission of MSE's use of normalization. With such approval, the benefits of tax depreciation will be recognized in rates over the life of the plant.

In its Initial Brief, the FERC Staff concluded that MSE had substantiated its claim that the Unit Power Sales Agreement meets all applicable tax normalization requirements (Staff Br., pp. 61-62). Since no other party has raised this question, MSE's use of tax normalization is no longer an issue in the case. In a footnote, however, Staff suggests that MSE's sample calculation of income tax expense should be incorporated as an algebraic tax formula in MSE's proposed billing format. Staff's suggestion is not accepted.

There is no reason to include an algebraic income tax formula in the Agreement to show MSE's normalization practice, assuming such a formula could be devised. Staff has offered no reason to support the inclusion of a tax formula, nor has Staff provided any support for the use of the sample calculation of income tax expense as a surrogate for an algebraic formula. Staff does not cite any other unit power sales agreement on file with the FERC in which income taxes were represented in the rates by an algebraic formula such as Staff appears to be suggesting.

Furthermore, as Staff noted, MSE's sample tax calculation reflected uncertainty regarding whether operations of Grand Gulf Unit No. 1 would be subject to Mississippi income taxes. It would be inappropriate to attempt to fashion a tax formula for inclusion in the Billing Format prior to the time questions regarding the applicability of Mississippi income taxes are resolved.

It is held hat MSE's use of tax normalization satisfies the requirements of ERTA and of order Nos. 144 and 144-

A, and that no modification to the Unit Power Sales Agreement or Billing format is required at this time.

L. Incentive Rate of Return

The next issue is whether MSE's rate of return should contain an incentive provision based on the energy production of the Grand Gulf units.

Mr. Flaherty, testifying on behalf of the Mississippi Public Service Commission, recommended that the Unit Power Sales Agreement be modified to include an availability incentive provision (Ex. 44, pp. 25-31). His incentive provision would allow MSE an incremental increase to return on equity when MSE surpasses a target level of plant availability and an incremental decrease from return on equity when MSE falls to achieve that target (*Id.*, p. 29). The actual availability would be computed from the four most recent quarters of plant utilization and compared to the target *(Id.)*. The target would be set at one level during the first two years of operation and then at a second higher level (*Id.*, p. 30).

In an illustrative example, Mr. Flaherty used a target plant availability of 50% during the first two years, and 65% thereafter. Assuming an authorized 16% rate of return on common equity, the adjustment would work as follows:

Availability Factor	*Return on Equity*
75.01% and Above	+ .50%
73.01% to 75.00%	+ .40%
71.01% to 73.00%	+ .30%
69.01% to 71.00%	+ .20%
67.01% to 69.00%	+ .10%
65.01% to 67.00%	+ .05%
65%	16.00%
63.00% to 64.99%	- .05%
61.00% to 62.99%	- .10%
59.00% to 60.99%	- .15%
57.00% to 58.99%	- .20%
55.00% to 56.99%	- .25%
54.99% and Below	- .30%

On cross examination Mr. Flaherty stated that he intended his incentive provision to be based on output, not availability, but the capacity factor is closer to the concept he is advocating than output (Tr. 2346). He testified that other bases for incentive might be kilowatt-hours produced for a stated period of time or fuel expense (Tr. 2347-49). He thought there was merit in implementing an incentive provision after two years of operation (Tr. 2349-50). Once fixed, the target should not need to be adjusted (Tr. 2350-51). He also thought that a four quarter average would be reasonable (as opposed to more or fewer quarters) (Tr. 2351-52), and that quarters where refueling takes place or where forced outages beyond the control of management occur might be omitted (Id.). He testified that a 65 percent availability factor is a reasonable target for nuclear plants unless there is a good reason for selecting another target (Tr. 2353-54). The skew Mr. Flaherty proposes in Exhibit 44, p. 30 (a 10% increase in availability factor rewards the utility with a 0.5% increasing in rate of return, but a 10% decrease in availability factor penalizes the utility with only 0.3% decrease in rate of return), is reasonable because it is more difficult to reach a higher capacity factor than a lower one (Tr. 2354-56).

On rebuttal Ms. Streiter, testifying for MSE, stated that incentives have a place in utility pricing in general, but that incentives applied to nuclear plant efficiency may introduce safety risks (Ex. 91, p. 1). She proposed five criteria which she believed were relevant in this docket: (1) incentives must be tailored to elements of cost over which the utility has some control (*Id.*, pp. 2-5; Ex. 92); (2) the target selected must be fair and reasonable (Ex. 91, pp. 5-6); (3) an incentive must be even-handed: "good" performance should be rewarded if "poor" performance is penalized (*Id.*, pp. 6-7); (4) concern for efficiency should be balanced with concern for exposure of net income because large downside risks on net income would raise financing costs (*Id.*, p. 7); and (5) all elements of cost should be in an incentive (*Id.*, pp. 7-9). Ms. Streiter indicated that limiting the incentive to elements of cost over which the utility has control may be difficult. Her study purported to show that random effects were substantial. She pointed out that random effects would be diminished as the number of plants were increased (*Id.*, p. 3-5; Ex. 92). She indicated that Mr. Flaherty's availability target of 65% was too high when compared to data she has studied (Ex. 91, pp. 5-7). She pointed out that there should be a dead zone or null zone around the target *(Id.)*. Ms. Streiter agreed with Mr. Flaherty's skewed penalty/reward proposal (*Id.*, p. 7) as well as his balance of concern for efficiency with concern for exposure of net income *(Id.)*. However, she criticized Mr. Flaherty's proposed consecutive rolling quarters of utilization and capacity factor criteria, because after a plant is down for a certain length of time there would be a disincentive to putting a plant back on the line and an incentive to over-expend on maintenance (*Id.*, pp. 7-8). On cross examination Ms. Streiter testified that the question of the controllability of any item is relative (Tr. 1626); she had given little thought to whether incentives should be linear or nonlinear (Tr. 1626-27); even-handedness actually means a slight skewness from equal above and equal below

(Tr. 1628-29); there is room for more thought as to how large a penalty should be when the ultimate objective is to minimize the cost to consumers (Tr. 1629-30); the size of the dead band is not a precise number, but should be related to the precision with which one can reasonably estimate a target (Tr. 1641-43); she is uncomfortable with applying an incentive proposal such as Mr. Flaherty's to utilities with nuclear plants in general, and to utilities with a single nuclear plant in particular (Tr. 1642-43); and any target should be revised periodically as better information becomes available.

The incentive availability provision is supported by the Mississippi Public Service Commission and by Occidental Chemical Corporation. They argue that the use of such a provision would provide the utility with an incentive to provide the ratepayer with the most economical cost of power through efficient production of power, because the higher the capacity factor the lower the cost per kilowatt-hour of power produced. Occidental also argues that an incentive provision is particularly appropriate in the instant case, where MSE seeks a cost-of-service formula under which all of the costs of operating the unit will be recovered irrespective of the performance of the unit. Occidental notes that capacity factor is one of the three most important elements in determining the cost per kilowatt-hour of Grand Gulf (Ex. 89, p. 7; Tr. 1535). Occidental also notes that the Commission directed its Staff to negotiate "a sliding rate of return tied to generating unit performance" for nuclear and coal units owned by Virginia Electric Power Company (Vepco). *Virginia Electric Power Co.*, 19 FERC ¶61,333 (June 28, 1982); see Tr. 1601-2. An uncontested settlement agreement, which established a performance incentive program tying Vepco's rate of return to generating unit performance, was approved by the Commission. Letter Order, *Virginia Electric Power Co.*, Docket No. ER82-423-000 [23 FERC ¶61,210] (May 2, 1983).

Staff and MSE argue against the imposition of an incentive provision, although Staff is not as categorically opposed as MSE. Staff submits that incentive rates of return have merit as a general concept, but Staff believes a number of questions should be explored more thoroughly either in a separate phase of this proceeding or in a general rulemaking, before an incentive provision should be imposed on MSE. The issues which Staff believes require more thought before an incentive provision is imposed on MSE are: (1) Which measure of efficiency should be selected as the incentive? (2) How does one choose the target? (3) Should a target be fixed during some period of time, or altered at stated intervals? (4) How does one insure that random events have been excluded from the measure of efficiency? (5) Should there be a dead zone and how does one decide the size of the dead zone? (6) How much skew should be introduced in the measure? (7) Should incentive rates of return be applied to utilities which operate only nuclear plants? (8) Should incentive rates be applied to utilities which operate a single generating plant? (9) How should plant shut-downs resulting from industry-wide design defects be treated?

Staff notes that while an incentive return was approved by the Commission in *Virginia Electric & Power Company*, Docket No. ER82-423-000, the incentive provision was contained in a settlement, and the derivation of the incentive return was a fairly complex process.

Considering the arguments of the parties and the evidence, I find that the incentive provision advocated by the Mississippi Public Service Commission and Occidental Chemical Corporation should not be adopted in this proceeding. The dominant concern with respect to operation of a nuclear power plant is that it be operated safely. Yet adoption of an availability incentive provision might induce MSE to take undue safety risks to improve plant availability (Tr. 1641; Ex. 91, pp. 1-8).

Moreover, an availability incentive provision will be effective only if the availability of the plant is subject to matters within managerial control (Ex. 91, pp. 1-3). However, the availability of any single nuclear power plant is subject to a substantial degree of randomness, unrelated to managerial discretion (Tr. 1607-1608, 1616-1618, 1650; Ex. 91, pp. 3-5; Ex. 92). Factors affecting the availability of a nuclear power plant over which the utility has little, if any, control include shutdowns ordered by the Nuclear Regulatory Commission for inspection and/or modification, design problems in a particular group of plants, and random mechanical failures (Ex. 91, p. 3). While the effect of such random factors may be substantially mitigated if several generating units are encompassed within the availability incentive provision, they may prevent proper operation of such a provision relating to a single nuclear plant.

Under Mr. Flaherty's proposal, the availability of Grand Gulf would be measured in terms of the four most recent consecutive quarters of use (Ex. 44, p. 29). However, the availability of nuclear power plants varies substantially from year to year because of refueling (Tr. 1618; Ex. 91, p. 5). For this reason adoption of Mr. Flaherty's proposal could lead to substantial fluctuations in MSE's revenue from year to year (Ex. 91, p. 5).

While the target availability factors of 50 percent during the first two years and 65 percent thereafter are, in Mr. Flaherty's opinion, "achieveable in terms of how other nuclear plants are operating" (Ex. 44, p. 30), they are in excess of those experienced by other large boiling water reactors (Ex. 91, p. 5). Moreover, Grand Gulf has been shown to be economically beneficial even if only a 60 percent availability factor is achieved (Ex. 89, p. 14; Ex. 90). Adoption of too high a target would deny MSE the ability to earn the rate of return found by the Commission in this proceeding to be just as reasonable.

Another problem with Mr. Flaherty's proposal is that penalties are assessed or rewards granted if the actual plant availability is 0.01 percent lower or higher than the target (Ex. 44, p. 30; Ex. 91, p. 6). Such tight tolerance is inappropriate. Because the target is the expected average availability to be achieved, there should be a null zone around the target within which the availability might vary without causing changes in income (Tr. 1641, 2357-2358; Ex. 91, p. 6). The Mississippi Public Service Commission concedes that Mr. Flaherty was uncertain whether the proper incentive provision should be based on the availability of Grand Gulf, the capacity factor of Grand Gulf, or some other basis (Tr. 2345-2348). He further agreed to deferral of implementation of an incentive provision until completion of a shakedown period, the length of which varies from plant to plant (Tr. 2350). Similarly, Mr. Flaherty agreed that the period of time for which the capacity factor should be analyzed should reflect a time period which will provide a reasonable amount of information upon which performance can be measured, whether four quarters of operation or longer, an unspecified dead zone around the selected target should be established, and a proper skew in the distribution of the incentive return element variance should be adopted.

Finally, Mr. Flaherty conceded that his incentive proposal should have, but did not contain, a provision for recognition of matters beyond management's control, such as forced outages and refueling outages (Tr. 2350-51). Further, he would require that information regarding all forced outages be submitted to the FERC Staff for a determination whether it was related to maintenance or other matters within the control of management, or matters such as the type of the plant or NRC directives which are not within managerial control (Tr. 2352).

Based upon the evidence, the foregoing discussion and the concerns raised by Staff, I find that there is insufficient evidence in this record and too many unanswered

questions to require the Unit Power Sales Agreement at this time to contain an incentive provision based on the energy production of the Grand Gulf Units. The Commission may wish to consider, however, whether a separate proceeding should be commenced to explore the design of such a provision for MSE.

M. Refiling the Unit Power Sales Agreement Under Section 205

The next issue is whether MSE should be required to refile its Unit Power Sales Agreement every five years under Section 205 of the Federal Power Act, 16 U.S.C. § 824d (Tr. 251).

The Unit Power Sales Agreement, with its cost-of-service formula rate, will be effective for the life of the Grand Gulf plant. Because the formula will adjust charges automatically to track operating costs, it will not be necessary for MSE to file rate changes to properly recover such costs. Rate change filings by MSE will be necessary only if the amounts recovered under the formula are insufficient to compensate for rate of return on common equity, the rate at which depreciation expense is accrued and nuclear decommissioning expenses (Ex. 62, pp. 4-5).

Staff contends that the Agreement should be refiled by MSE with the Commission in a Section 205 proceeding not less often than once every five years. The Louisiana Commission argues that MSE make such a filing every three years. MSE opposes both proposals. No other participant has taken a position on the issue.

The arguments in favor of refiling may be briefly summarized. Because a cost-of-service formula rate is an exception to the requirement of Section 205 of the Federal Power Act that changes in rates be filed with the Commission and be subject to notice, suspension and refund, the burden of proving that the formula rate is working properly should be on MSE in a Section 205 proceeding

and not on a complainant in a Section 206 proceeding where there are no rate suspensions and refunds. Regular audits by FERC are not a sufficient protection to consumers when a nuclear generating plant costing over $2.5 billion is going on line. Without a requirement for refiling every five years, the formula rates may apply for the 40 years of the plant's estimated useful life. The dollar impact on the consumer of the formula rates is enormous. Once a cost enters the formula, the affected state commission is required to flow that cost through to rate payers. Further, some costs, such as decommissioning costs, are simply best guesses as to what the actual decommissioning costs will be. By requiring a Section 205 filing at least once every five years, this Commission would have the opportunity to reevaluate such matters as nuclear decommissioning costs and the way the formula is working; in addition, as the Commission changes its policies, the Commission could assure itself that MSE had adjusted accounts and components of the formula rate properly in light of the new policies.

The undersigned judge is sympathetic to the concerns of Staff and the Louisiana Public Service Commission. *See, Middle South Services, Inc.,* Initial Decision, 13 FERC ¶63,032, pp. 65,104-105 (1980). When rate increases under purchased gas adjustment clauses are filed by gas pipelines, the Commission requires at least every three years a full review under Section 4 of the Natural Gas Act of the pipeline's costs, and the Commission can order refunds. 18 C.F.R. § 154.38(d)(4)(iv-vi); *Associated Gas Distributors v. F.E.R.C.,* 706 F.2d 344, 346 (D.C. Cir. 1983). Section 205 of the Federal Power Act is the section analagous to Section 4 of the Natural Gas Act. The purchased gas adjustment clause performs a function similar to the cost-of-service formula advocated by MSE in the instant case: in an era where costs are escalating rapidly, both the purchased gas adjustment clause and the cost-of-service for-

mula rate allow the utility to quickly recover costs without making multiple rate filings.

The customers of gas pipelines are protected by the Commission's Section 4 review of rate increases due to purchased gas cost adjustments. It would seem that similar protection ought to be afforded electric customers subject to formula rates under an automatic adjustment clause. The refiling requirement advocated by Staff and the Louisiana Commission would afford electric customers protection similar to what the FERC affords gas customers subject to rate increases from purchased gas adjustment clauses.

If the Commission had not decided *Middle South Services, Inc.*, Opinion No. 124, 16 FERC ¶61,101 (1981), *aff'd, Louisiana Public Service Commission v. F.E.R.C.*, 688 F.3d 357 (5th Cir. 1982), *cert. denied,* 103 S. Ct. 1770 (1983), and *Southern Company Services, Inc.*, 22 FERC ¶61,047, p. 61,084 (1983), I would follow Staff's suggestion or impose a similar filing requirement. However, I am constrained by the Commission's rulings in the two cases just cited.

In *Southern Company Services Inc.*, 22 FERC ¶61,047 (1983), the Commission, relying on the *Middle South Services* case, refused to impose filing and review requirements on a unit power sales agreement containing a cost-of-service formula rate. The Commission said (p. 61,084):

> the formulary methodologies reflect treatment of the cost of service components in a manner substantially consistent with Commission precedent. Accordingly, the formulary rates for determining charges under the Unit Power Sales Agreement will not be subject to periodic review procedures.

It is held that MSE will not be required to refile its Unit Power Sales Agreement once every five (or three) years under Section 205 of the Federal Power Act.

N. Levelization

The next issue is whether the tariff in the Unit Power Sales Agreement should include a provision for the optional levelization of charges at the retail level (Tr. 251).

MSE proposes to recover, and LP&L, MP&L, and NOPSI have agreed to pay for, MSE's cost of service pursuant to the Unit Power Sales Agreement (Ex. 7; Ex. 61, p. 2). To moderate the initial impact on their respective retail customers of the cost of power from Grand Gulf Unit No. 1, LP&L and NOPSI have proposed to the Louisiana Public Service Commission that they defer collection from their retail customers of a portion of their costs of purchasing power from Grand Gulf Unit No. 1 during its early years of operation (Ex. 97; Ex. 128). This proposal has been dubbed "levelization" in the instant proceeding.

In this prepared testimony, Mr. Louiselle, a witness for the Louisiana Commission, asserted that the FERC should determine whether such a procedure is needed to mitigate the rate impact of the cost of power from Grand Gulf during its early years of operation, and, if so, what that procedure should be (Ex. 41, pp. 18-19). He recommended that "MSE be required to propose a levelized charge plan which would be available to each of the Grand Gulf participants on an optional basis" (Ex. 41, p. 20).

On cross examination, Mr. Louiselle clarified his testimony. First, he endorsed the kind of phase-in proposal previously presented to the Louisiana Commission by LP&L and NOPSI (Tr. 2289-90, 2292-95). Second, he agreed that each of the MSU operating companies should pay MSE the full cost of power purchased from Grand Gulf. He proposed that MSE calculate an alternative bill each month showing the levelized amounts which would have been payable to MSE by each of the MSU operating companies if such a phase-in of the cost of power had been adopted for MSE (Tr. 2288-2290). Under his proposal, phase-in of the costs of power from Grand Gulf in its retail

rates by any of the system operating companies would be based on this alternative bill (Tr. 2292).

In its proposed conclusions of law, the Louisiana Commission states (Initial Brief, pp. 117-118):

> . . . Since the FERC has jurisdiction to establish the rates for the power and energy from Grand Gulf, it is possible that state public service commissions may be required to include the full amount of the charges in retail rates. Thus, for example, if the charge under the tariff to LP&L in the first month is $20 million, the Louisiana Commission might be precluded from "levelizing" the charge and including less than $20 million in retail rates. See, *Narragansett Electric Company v. Burke,* 381 A.2d 1358, 23 PUR 4th 509 (R.I. 1977). The only way to ensure that state commissions will be permitted to institute levelization plans is to make provision for those plans in the FERC approved tariff.

The Louisiana Commission then proposes that FERC's decision in the instant case contain the following statement:

> The state public service commissions are given the option of adopting a levelization plan of the type proposed by LP&L and NOPSI in their retail rate proceedings and filed as Exhibit 97 in this case.

Considering the evidence, the law, and the arguments of the parties, I decline to make the statement requested by the Louisiana Commission, and I decline to require the insertion into MSE's tariff of a provision for levelizing charges at the retail level. The design of local retail rates to ultimate consumers is a matter within the jurisdiction of the states. *F.P.C. v. Southern California Edison Co.,* *376* U.S. 205, 214 (1964). While the states cannot disallow as an operating expense a wholesale rate filed or fixed by the Federal Energy Regulatory Commission, *Narragansett*

Electric Co. v. Burke, 119 R.I. 559, 381 A.2d 1358, 1362 (1977), *cert. denied, Burke v. Narragansett Electric Co.*, 435 U.S. *972* (1978); *United Gas Corp. v. Mississippi Public Service Comm'n,* 240 Miss. 405, 442-443, 127 So.2d 404, 420 (1961), the authorities cited to me do not necessarily preclude the levelization of charges at the state retail level. Whether a state retail levelization scheme would have the effect of disallowing as an operating expense the wholesale rate fixed by the Federal Energy Regulatory Commission or whether such a levelization scheme would be otherwise illegal are questions which may turn on the particular levelization scheme adopted by a State commission. The Federal Energy Regulatory Commission should not make general pronouncements now as to whether state retail levelization plans would be permissible or what kind of retail levelization plans would be permissible for the operating companies of MSU. Abstaining from such pronouncements seems particularly appropriate for FERC in light of the clear bright line which the Federal Power Act sought to draw between Federal and state jurisdiction over electric utilities. *F.P.C. v. Southern California Edison, Co., 376* U.S. at 215-16.

It is held that the tariff in the Unit Power Sales Agreement shall not include a provision for the optional levelization of charges at the retail level. This ruling is not meant, however, to preclude a state commission from adopting a levelization plan that is appropriate and legal.

O. Amortization Expenses and Gains and Losses From Utility Plant Disposition

The fifteenth and final issue is whether MSE's cost-of-service tariff should contain provisions for amortization expenses and gains and losses from disposition of utility plant (Tr. 582-583).

There is no direct testimony on the issue. It arose during the cross examination of MSE's witness Brown by counsel for LPSC.

MSE has included provisions for amortization expenses (Accounts 404 through 407) and gains and losses from disposition of utility plant (Accounts 411.6 and 411.7) in its cost-of-service formula rate (Ex. 8).

The Louisiana Commission argues that the provisions for amortization expenses (Accounts 404 through 407) and gains and losses from disposition of utility plant (Accounts 411.6 and 411.7) should be excluded from MSE's cost-of-service formula rate (LPSC Initial Brief, pp. 60-61). The following is a list of the individual accounts which LPSC contends should be eliminated: Account 404—Amortization of limited-term electric plant; Account 405—Amortization of other electric plant; Account 406—Amortization of electric plant acquisition adjustments; Account 407—Amortization of property losses; Account 411.6—Gains from disposition of utility plant; Account 411.7—Losses from disposition of utility plant.

In support of its argument, LPSC stated that MSE does not anticipate any activity in these accounts and that advance FERC approval for the use of these accounts would be required in any event. The LPSC also contends that MSE's witness Brown conceded on cross examination that "inclusion of these items for automatic pass-through of the expenses in unnecessary" (LPSC Initial Brief, p. 60).

Staff also opposes the inclusion of these accounts in MSE's formula rate because the Commission must first approve any abandonment costs and amortization expenses from disposition of utility plant before such costs may be included in a rate and charged to customers.

MSE argues that the inclusion of Accounts 404 through 407 and Accounts 411.6 and 411.7 in a cost-of-service formula rate is not without precedent. These accounts have been permitted in Connecticut Yankee Atomic Power Company's FPC Electric Rate Schedule No. 1, Exhibit B, a unit power sales agreement similar to the one at issue here. MSE notes that Commission precedent on plant

abandonment losses is clear. The losses, MSE argues, are legitimate costs which must be reflected in the cost of providing electric service. *Southern California Edison Co.*, Opinion No. 821, 59 FPC 2167 (1977); *Union Electric Co. v. F.E.R.C.*, 668 F.2d 389 (8th Cir. 1981); *Northern States Power Co.*, Opinion No. 134, 17 FERC ¶61,196 (1981); *New England Power Co.*, Opinion No. 49, 8 FERC ¶61,054 (1979), *aff'd NEPCO Mun. Rate Com. v. F.E.R.C.*, 668 F.2d 1327 (D.C. Cir. 1981), *cert. denied*, 457 U.S. 1117 (1982).

However, MSE concedes that before the costs associated with plant abandonment can be included in Account 407—Amortization of Property Losses, the Commission must authorize the amortization of extraordinary property losses. 18 C.F.R. Part 101, Account 407. Similarly, Accounts 405 and 406, covering amortization charges, and Accounts 411.6 and 411.7, covering gains and losses from disposition of utility plant, can only be used when authorized by the Commission. 18 C.F.R. Part 101. MSE also states that use of Account 404—Amortizaton of limited-term electric plant, does not require Commission approval for its use.

In order for cancelled or abandoned plants to be written off, the Commission must determine that the costs were prudently incurred and determine a reasonable amortization period. *See, Northern States Power Company*, Opinion No. 134, *supra; Southern California Edison Company*, Opinion No. 62, 8 FERC ¶61,198 (1979); *reh. denied*, Opinion No. 62-A, 10 FERC ¶61,260 (1980); *aff'd sub nom., Anaheim v. F.E.R.C.*, 669 F.2d 799 (D.C. Cir. 1981); *New England Power Company*, Opinion No. 49, 8 FERC ¶61,054 (1979); Opinion No. 49-A, 10 FERC ¶61,279 (1980); *aff'd sub nom., NEPCO Municipal Rate Committee v. F.E.R.C.*, 668 F.2d 1327 (D.C. Cir. 1981); *cert. denied*, 457 U.S. 1117 (1982).

None of the contentions advanced by LPSC and Staff requires deletion of these provisions from the cost-of-ser-

vice formula rate. The fact that Commission approval is a condition precedent to the use of these accounts does not obviate the need for a mechanism by which amounts approved by the Commission may be recovered.

What seems to have prompted this issue was LPSC's fear that the costs attributable to Grand Gulf Unit No. 2, if the unit were not completed, would flow through MSE's formula rate without regulatory approval. However, this Initial Decision has held that the automatic adjustment clause in the Unit Power Sales Agreement should not apply to Grand Gulf Unit No. 2 at this time.

It is held that provisions for amortization expenses and gains and losses from disposition of utility plant may be contained in MSE's cost-of-service formula rate, and it is further held that no amounts are to be included in Accounts 404 through 407 and in Accounts 411.6 and 411.7 without prior approval by FERC.

IV. Additional Findings and Conclusions

Upon consideration of the entire record in this case and the briefs and arguments of the parties, it is further found and concluded that:

(1) Arkansas Power & Light Company, Louisiana Power & Light Company, Mississippi Power & Light Company, New Orleans Public Service Inc. and Middle South Energy, Inc., are subsidiaries of Middle South Utilities, Inc., and are public utilities within the meaning of the Federal Power Act, 16 U.S.C. §824, *et seq.*, as amended.

(2) The sales of electric energy from the Grand Gulf Nuclear Generating Station by Middle South Energy, Inc., under the Unit Power Sales Agreement which is the subject of this proceeding are sales of electric energy at wholesale in interstate commerce and thus subject to the jurisdiction of the Federal Energy Regulatory Commission.

(3) The rates, charges, and classifications which have been proposed by Middle South Energy, Inc., in the Unit Power Sales Agreement have not been shown to be just and reasonable or otherwise lawful under the provisions of the Federal Power Act in the respects noted in this Initial Decision, and Middle South Energy, Inc., should therefore be required to file just and reasonable rates as necessary to conform to this Initial Decision.

(4) The rates required to be filed by, and computed in accordance with, this Initial Decision are just and reasonable and otherwise lawful.

(5) Middle South Energy, Inc., should be required to refund to its customers any amounts reflecting the difference between the rates proposed and the rates required to be filed by this Initial Decision.

Order

Wherefore, it is ordered, subject to review by the Commission on appeal or on its own motion, as provided in the Commission's Rules of Practice and Procedure:

(A) The rates filed by Middle South Energy, Inc., which have been in effect in this docket subject to refund, are disallowed to the extent they do not conform to this Initial Decision.

(B) Within 30 days after the effective date of this Initial Decision, Middle South Energy, Inc., shall file any necessary amendments to the Unit Power Sales Agreement and the schedules thereunder in accordance with the findings and conclusions of this Initial Decision and with the Commission's Rules and Regulations, subject to the approval of the Commission.

(C) Within 30 days of the Commission's approval of the revised filing of Middle South Energy, Inc., in accordance with paragraph (B), *supra,* of this order, Middle South

Energy, Inc., shall refund to its customers any amounts collected in excess of the amounts which would have been payable under the rates and changes approved in accordance with paragraph (B), *supra,* together with interest at the rates established by the Commission, from the date of payment to the date of refund.

APPENDIX F

STATUTE INVOLVED

16 U.S.C. §824, et seq.

Federal Power Act—Parts II & III

SUBCHAPTER II—REGULATION OF ELECTRIC UTILITY COMPANIES ENGAGED IN INTERSTATE COMMERCE

§ 824. Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmis-

sion or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in interstate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

(2) The provisions of sections 824i, 824j, and 824k of this title shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this chapter with respect to such provisions. Compliance with any order of the Commission under the provisions of section 824i, or 824j of this title, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.

(c) Electric energy in interstate commerce

For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale" defined

The term "sale of electric energy at wholesale" when used in this subchapter, means a sale of electric energy to any person for resale.

(e) "Public utility" defined

The term "public utility" when used in this subchapter and subchapter III of this chapter means any person who

owns or operates facilities subject to the jurisdiction of the Commission under this subchapter (other than facilities subject to such jurisdiction solely by reason 824i, 824j, or 824k of this title).

(f) United States, State, political subdivision of State, or agency or instrumentality thereof exempt

No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

§ 824a. Interconnection and coordination of facilities; emergencies; transmission to foreign countries

(a) Regional districts; establishment; notice to State commissions

For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnected and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within

each such district and between such districts. Before establishing any such district and fixing or modifying the boundaries thereof the Commission shall give notice to the State commission of each State situated wholly or in part within such district, and shall afford each such State commission reasonable opportunity to present its views and recommendations, and shall receive and consider such views and recommendations.

(b) Sale or exchange of energy; establishing physical connections

Whenever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility (if the Commission finds that no undue burden will be placed upon such public utility thereby) to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: *Provided,* That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers. The Commission may prescribe the terms and conditions of the arrangement to be made between the persons affected by any such order, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them.

(c) Temporary connection and exchange of facilities during emergency

During the continuance of any war in which the United States is engaged, or whenever the Commission deter-

mines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

(d) Temporary connection during emergency by persons without jurisdiction of Commission

During the continuance of any emergency requiring immediate action, any person engaged in the transmission or sale of electric energy and not otherwise subject to the jurisdiction of the Commission may make such temporary connections with any public utility subject to the jurisdiction of the Commission or may construct such temporary facilities for the transmission of electric energy in interstate commerce as may be necessary or appropriate to meet such emergency, and shall not become subject to the jurisdiction of the Commission by reason of such temporary connection or temporary construction: *Provided*, That such temporary connection shall be disconnected or such temporary construction removed or otherwise disposed of upon the termination of such emergency: *Provided further*, That upon approval of the Commission permanent connections for emergency use only may be made hereunder.

(e) Transmission of electric energy to foreign country

After six months from August 26, 1935, no person shall transmit any electric energy from the United States to a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of the Commission. The Commission may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as the Commission may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate.

(f) Transmission or sale at wholesale of electric energy; regulation

The ownership or operation of facilities for the transmission or sale at wholesale of electric energy which is (a) generated within a State and transmitted from that State across an international boundary and not thereafter transmitted into any other State, or (b) generated in a foreign country and transmitted across an international boundary into a State and not thereafter transmitted into any other State, shall not make a person a public utility subject to regulation as such under other provisions of this subchapter. The State within which any such facilities are located may regulate any such transaction insofar as such State regulation does not conflict with the exercise of the Commission's powers under or relating to subsection (e) of this section.

(g) Continuance of service

In order to insure continuity of service to customers of public utilities, the Commission shall require, by rule, each public utility to—

(1) report promptly to the Commission and any appropriate State regulatory authorities any anticipated shortage of electric energy or capacity which would affect such utility's capability of serving its wholesale customers,

(2) submit to the Commission, and to any appropriate State regulatory authority, and periodically revise, contingency plans respecting—

(A) shortages of electric energy or capacity, and

(B) circumstances which may result in such shortages, and

(3) accommodate any such shortages or circumstances in a manner which shall—

(A) give due consideration to the public health, safety, and welfare, and

(B) provide that all persons served directly or indirectly by such public utility will be treated, without undue prejudice or disadvantage.

The Secretary shall report annually to the Congress on the actions, if any, taken pursuant to this section.

§ 824b. Disposition of property; consolidations; purchase of securities

(a) Authorizations

No public utility shall sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, or any part thereof of a value in excess of $50,000, or by any means whatsoever, directly or in-

directly, merge or consolidate such facilities or any part thereof with those of any other person, or purchase, acquire, or take any security of any other public utility, without first having secured an order of the Commission authorizing it to do so. Upon application for such approval the Commission shall give reasonable notice in writing to the Governor and State commission of each of the States in which the physical property affected, or any part thereof, is situated, and to such other persons as it may deem advisable. After notice and opportunity for hearing, if the Commission finds that the proposed disposition, consolidation, acquisition, or control will be consistent with the public interest, it shall approve the same.

(b) Orders of Commission

The Commission may grant any application for an order under this section in whole or in part and upon such terms and conditions as it finds necessary or appropriate to secure the maintenance of adequate service and the coordination in the public interest of facilities subject to the jurisdiction of the Commission. The Commission may from time to time for good cause shown make such orders supplemental to any order made under this section as it may find necessary or appropriate.

§ 824c. Issuance of securities; assumption of liabilities

(a) Authorization by Commission

No public utility shall issue any security, or assume any obligation or liability as guarantor, indorser, surety, or otherwise in respect of any security of another person, unless and until, and then only to the extent that, upon application by the public utility, the Commission by order authorizes such issue or assumption of liability. The Commission shall make such order only if it finds that such issue or assumption (a) is for some lawful object, within the corporate purposes of the applicant and compatible

with the public interest, which is necessary or appropriate for or consistent with the proper performance by the applicant of service as a public utility and which will not impair its ability to perform that service, and (b) is reasonably necessary or appropriate for such purposes. The provisions of this section shall be effective six months after August 26, 1935.

(b) Application approval or modification; supplemental orders

The Commission, after opportunity for hearing, may grant any application under this section in whole or in part, and with such modifications and upon such terms and conditions as it may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate, and may by any such supplemental order modify the provisions of any previous order as to the particular purposes, uses, and extent to which, or the conditions under which, any security so theretofore authorize or the proceeds thereof may be applied, subject always to the requirements of subsection (a) of this section.

(c) Compliance with order of Commission

No public utility shall, without the consent of the Commission, apply any security or any proceeds thereof to any purpose not specified in the Commission's order, or supplemental order, or to any purpose in excess of the amount allowed for such purpose in such order, or otherwise in contravention of such order.

(d) Authorization of capitalization not to exceed amount paid

The Commission shall not authorize the capitalization of the right to be a corporation or of any franchise, permit,

or contract for consolidation, merger, or lease in excess of the amount (exclusive of any tax or annual charge) actually paid as the consideration for such right, franchise, permit, or contract.

(e) Notes or drafts maturing less than one year after issuance

Subsection (a) of this section shall not apply to the issue or renewal of, or assumption of liability on, a note or draft maturing not more than one year after the date of such issue, renewal, or assumption of liability, and aggregating (together with all other then outstanding notes and drafts of a maturity of one year or less on which such public utility is primarily or secondarily liable) not more than 5 per centum of the par value of the other securities of the public utility then outstanding. In the case of securities having no par value, the par value for the purpose of this subsection shall be the fair market value as of the date of issue. Within ten days after any such issue, renewal, or assumption of liability, the public utility shall file with the Commission a certificate of notification, in such form as may be prescribed by the Commission, setting forth such matters as the Commission shall by regulation require.

(f) Public utility securities regulated by State not affected

The provisions of this section shall not extend to a public utility organized and operating in a State under the laws of which its security issues are regulated by a State commission.

(g) Guarantee or obligation on part of United States

Nothing in this section shall be construed to imply any guarantee or obligation on the part of the United States in respect of any securities to which the provisions of this section relate.

(h) Filing duplicate reports with Securities and Exchange Commission

Any public utility whose security issues are approved by the Commission under this section may file with the Securities and Exchange Commission duplicate copies of reports filed with the Federal Power Commission in lieu of the reports, information, and documents required under sections 77g, 78l and 78m of Title 15.

§ 824d. Rates and charges; schedules; suspension of new rates; automatic adjustment clauses

(a) Just and reasonable rates

All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) Preference or advantage unlawful

No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Schedules

Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient

form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Notice required for rate changes

Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Suspension of new rates; hearings; five month period

Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint, at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule

and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may be further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f) Review of automatic adjustment clauses and public utility practices; action by Commission; definition

(1) Not later than 2 years after November 9, 1978 and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are—

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to—

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause,

if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without

prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.

§ 824e. Power of Commission to fix rates and charges; determination of cost of production or transmission

(a) Unjust or preferential rates, etc.

Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

(b) Investigation of costs

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

§ 824f. Ordering a furnishing of adequate service

Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing,

shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: *Provided,* That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel the public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

§ 824g. Ascertainment of cost of property and depreciation

(a) Investigation of property costs

The Commission may investigate and ascertain the actual legitimate cost of the property of every public utility, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation, and the fair value of such property.

(b) Request for inventory and cost statements

Every public utility upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.

§ 824h. References to State boards by Commission

(a) Composition of boards; force and effect of proceedings

The Commission may refer any matter arising in the administration of this subchapter to a board to be composed of a member or members, as determined by the Commission, from the State or each of the States affected or to be affected by such matter. Any such board shall be vested with the same power and be subject to the same

duties and liabilities as in the case of a member of the Commission when designated by the Commission to hold any hearings. The action of such board shall have such force and effect and its proceedings shall be conducted in such manner as the Commission shall by regulations prescribe. The board shall be appointed by the Commission from persons nominated by the State commission of each State affected, or by the Governor of such State if there is no State commission. Each State affected shall be entitled to the same number of representatives on the board unless the nominating power of such State waives such right. The Commission shall have discretion to reject the nominee from any State, but shall thereupon invite a new nomination from that State. The members of a board shall receive such allowances for expenses as the Commission shall provide. The Commission may, when in its discretion sufficient reason exists therefor, revoke any reference to such a board.

(b) Cooperation with State commissions

The Commission may confer with any State commission regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission; and the Commission is authorized, under such rules and regulations as it shall prescribe, to hold joint hearings with any State commission in connection with any matter with respect to which the Commission is authorized to act. The Commission is authorized in the administration of this chapter to avail itself of such cooperation, services, records, and facilities as may be afforded by any State commission.

(c) Availability of information and reports to State commissions; Commission experts

The Commission shall make available to the several State commissions such information and reports as may be of

assistance in State regulation of public utilities. Whenever the Commission can do so without prejudice to the efficient and proper conduct of its affairs, it may upon request from a State make available to such State as witnesses any of its trained rate, valuation, or other experts, subject to reimbursement to the Commission by such State of the compensation and traveling expenses of such witnesses. All sums collected hereunder shall be credited to the appropriation from which the amounts were expended in carrying out the provisions of this subsection.

§ 824i. Interconnection authority

(a) Powers of Commission; application by State regulatory authority

(1) Upon application of any electric utility, Federal power marketing agency, geothermal power producer (including a producer which is not an electric utility), qualifying cogenerator, or qualifying small power producer, the Commission may issue an order requiring—

(A) the physical connection of any cogeneration facility, any small power production facility, or the transmission facilities of any electric utility, with the facilities of such applicant,

(B) such action as may be necessary to make effective any physical connection described in subparagraph (A), which physical connection is ineffective for any reason, such as inadequate size, poor maintenance, or physical unreliability,

(C) such sale or exchange of electric energy or other coordination, as may be necessary to carry out the purposes of any order under subparagraph (A) or (B), or

(D) such increase in transmission capacity as may be necessary to carry out the purposes of any order under subparagraph (A) or (B).

(2) Any State regulatory authority may apply to the Commission for an order for any action referred to in subparagraph (A), (B), (C), or (D) of paragraph (1). No such order may be issued by the Commission with respect to a Federal power marketing agency upon application of a State regulatory authority.

(b) Notice, hearing and determination by Commission

Upon receipt of an application under subsection (a) of this section, the Commission shall—

(1) issue notice to each affected State regulatory authority, each affected electric utility, each affected Federal power marketing agency, each affected owner or operator of a cogeneration facility or of a small power production facility, and to the public.[1]

(2) afford an opportunity for an evidentiary hearing, and

(3) make a determination with respect to the matters referred to in subsection (c) of this section.

(c) Necessary findings

No order may be issued by the Commission under subsection (a) of this section unless the Commission determines that such order—

(1) is in the public interest,

(2) would—

(A) encourage overall conservation of energy or capital,

(B) optimize the efficiency of use of facilities and resources, or

[1] So in original. Period probably should be a comma.

(C) improve the reliability of any electric utility system or Federal power marketing agency to which the order applies, and

(3) meets the requirements of section 824k of this title.

(d) Motion of Commission

The Commission may, on its own motion, after compliance with the requirements of paragraphs (1) and (2) of subsection (b) of this section, issue an order requiring any action described in subsection (a)(1) of this section if the Commission determines that such order meets the requirements of subsection (c) of this section. No such order may be issued upon the Commission's own motion with respect to a Federal power marketing agency.

(e) Definitions

(1) As used in this section, the term "facilities" means only facilities used for the generation or transmission of electric energy.

(2) With respect to an order issued pursuant to an application of a qualifying cogenerator or qualifying small power producer under subsection (a)(1) of this section, the term "facilities of such applicant" means the qualifying cogeneration facilities or qualifying small power production facilities of the applicant, as specified in the application. With respect to an order issued pursuant to an application under subsection (a)(2) of this section, the term "facilities of such applicant" means the qualifying cogeneration facilities, qualifying small power production facilities, or the transmission facilities of an electric utility, as specified in the application. With respect to an order issued by the Commission on its own motion under subsection (d) of this section, such term means the qualifying cogeneration facilities, qualifying small power production facilities, or the

transmission facilities of an electric utility, as specified in the proposed order.

§ 824j. Wheeling authority

(a) Transmission service by any electric utility; notice, hearing and findings by Commission

Any electric utility, geothermal power producer (including a producer which is not an electric utility), or Federal power marketing agency may apply to the Commission for an order under this subsection requiring any other electric utility to provide transmission services to the applicant (including any enlargement of transmission capacity necessary to provide such services). Upon receipt of such application, after public notice and notice to each affected State regulatory authority, each affected electric utility, and each affected Federal power marketing agency, and after affording an opportunity for an evidentiary hearing, the Commission may issue such order if it finds that such order—

(1) is in the public interest,

(2) would—

(A) conserve a significant amount of energy,

(B) significantly promote the efficient use of facilities and resources, or

(C) improve the reliability of any electric utility system to which the order applies, and

(3) meets the requirements of section 824k of this title.

(b) Transmission service by sellers of electric energy for resale; notice, hearing and determinations by Commission

Any electric utility, or Federal power marketing agency, which purchases electric energy for resale from any other

electric utility may apply to the Commission for an order under this subsection requiring such other electric utility to provide transmission services to the applicant (including any increase in transmission capacity necessary to provide such services). Upon receipt of an application under this subsection, after public notice and notice to each affected State regulatory authority, each affected electric utility, and each affected Federal power marketing agency, and after affording an opportunity for an evidentiary hearing, the Commission may issue such an order if the Commission determines that—

(1) such other electric utility has given actual or constructive notice that it is unwilling or unable to provide electric service to the applicant and has been requested in the application under this subsection, and

(2) such order meets the requirements of section 824k of this title.

(c) Preservation of competitive relationships; replacement of electric energy; inconsistent State laws

(1) No order may be issued under subsection (a) of this section unless the Commission determines that such order would reasonably preserve existing competitive relationships.

(2) No order may be issued under subsection (a) or (b) of this section which requires the electric utility subject to the order to transmit, during any period, an amount of electric energy which replaces any amount of electric energy—

(A) required to be provided to such applicant pursuant to a contract during such period, or

(B) currently provided to the applicant by the utility subject to the order pursuant to a rate schedule on file during such period with the Commission.

(3) No order may be issued under the authority of subsection (a) or (b) of this section which is inconsistent with any State law which governs the retail marketing areas of electric utilities.

(4) No order may be issued under subsection (a) or (b) of this section which provides for the transmission of electric energy directly to an ultimate consumer.

(d) Termination or modification of order; notice, hearing and findings of Commission; contends of order; inclusion in order of terms and conditions agreed upon by parties

(1) Any electric utility ordered under subsection (a) or (b) of this section to provide transmission services may apply to the Commission for an order permitting such electric utility to cease providing all, or any portion of, such services. After public notice, notice to each affected State regulatory authority, each affected Federal power marketing agency, and each affected electric utility, and after an opportunity for an evidentiary hearing, the Commission shall issue an order terminating or modifying the order issued under subsection (a) or (b) of this section, if the electric utility providing such transmission services has demonstrated, and the Commission has found, that—

(A) due to changed circumstances, the requirements applicable, under this section and section 824k of this title, to the issuance of an order under subsection (a) or (b) of this section are no longer met, or

(B) any transmission capacity of the utility providing transmission services under such order which was, at the time such order was issued, in excess of the capacity necessary to serve its own customers is no longer in excess of the capacity necessary for such purposes.

No order shall be issued under this subsection pursuant to a finding under subparagraph (A) unless the Commission finds that such order is in the public interest.

(2) Any order issued under this subsection terminating or modifying an order issued under subsection (a) or (b) of this section shall—

(A) provide for any appropriate compensation, and

(B) provide the affected electric utilities adequate opportunity and time to—

(i) make suitable alternative arrangements for any transmission services terminated or modified, and

(ii) insure that the interests of ratepayers of such utilities are adequately protected.

(3) No order may be issued under this subsection terminating or modifying any order issued under subsection (a) or (b) of this section if the order under subsection (a) or (b) of this section includes terms and conditions agreed upon by the parties which—

(A) fix a period during which transmission services are to be provided under the order under subsection (a) or (b) of this section, or

(B) otherwise provide procedures or methods for terminating or modifying such order (including, if appropriate, the return of the transmission capacity when necessary to take into account an increase, after the issuance of such order, in the needs of the electric utility subject to such order for transmission capacity).

(e) "Facilities" defined

As used in this section, the term "facilities" means only facilities used for the generation or transmission of electric energy.

§ 824k. Orders requiring interconnection or wheeling

(a) Determinations by Commission

No order may be issued by the Commission under section 824i of this title or subsection (a) or (b) of section

824j of this title unless the Commission determines that such order—

(1) is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility, qualifying cogenerator, or qualifying small power producer, as the case may be, affected by the order;

(2) will not place an undue burden on an electric utility, qualifying cogenerator, or qualifying small power producer, as the case may be, affected by the order;

(3) will not unreasonably impair the reliability of any electric utility affected by the order; and

(4) will not impair the ability of any electric utility affected by the order to render adequate service to its customers.

The determination under paragraph (1) shall be based upon a showing of the parties. The Commission shall have no authority under section 824i or 824j of this title to compel the enlargement of generating facilities.

(b) Reimbursement of parties subject to orders

No order may be issued under section 824i of this title or subsection (a) or (b) of section 824j of this title unless the applicant for such order demonstrates that he is ready, willing, and able to reimburse the party subject to such order for—

(1) in the case of an order under section 824i of this title, such party's share of the reasonably anticipated costs incurred under such order, and

(2) in the case of an order under subsection (a) or (b) of section 824j of this title—

(A) the reasonable costs of transmission services, including the costs of any enlargement of transmission facilities, and

(B) a reasonable rate of return on such costs, as appropriate, as determined by the Commission.

(c) Issuance of proposed order; agreement by parties to terms and conditions of order; approval by Commission; Inclusion in final order; failure to agree

(1) Before issuing an order under section 824i of this title or subsection (a) or (b) of section 824j of this title, the Commission shall issue a proposed order and set a reasonable time for parties to the proposed interconnection or transmission order to agree to terms and conditions under which such order is to be carried out, including the apportionment of costs between them and the compensation or reimbursement reasonably due to any of them. Such proposed order shall not be reviewable or enforceable in any court. The time set for such parties to agree to such terms and conditions may be shortened if the Commission determines that delay would jeopardize the attainment of the purposes of any proposed order. Any terms and conditions agreed to by the parties shall be subject to the approval of the Commission.

(2)(A) If the parties agree as provided in paragraph (1) within the time set by the Commission and the Commission approves such agreement, the terms and conditions shall be included in the final order. In the case of an order under section 824i of this title, if the parties fail to agree within the time set by the Commission or if the Commission does not approve any such agreement, the Commission shall prescribe such terms and conditions and include such terms and conditions in the final order.

(B) In the case of any order applied for under section 824j of this title, if the parties fail to agree within the time set by the Commission, the Commission shall prescribe such terms and conditions in the final order.

(d) Statement of reasons for denial

If the Commission does not issue any order applied for under section 824i or 824j of this title, the Commission shall, by order, deny such application and state the reasons for such denial.

(e) Utilization of interconnection or wheeling authority in lieu of other authority; limitation of Commission authority

No provision of section 824i or 824j of this title shall be treated—

(1) as requiring any person to utilize the authority of such section 824i or 824j of this title in lieu of any other authority of law, or

(2) as limiting, impairing, or otherwise affecting any authority of the Commission under any other provision of law.

(f) Effective date of order; hearing; notice; review

(1) No order under section 824i or 824j of this title requiring the Tennessee Valley Authority (hereinafter in this subsection referred to as the "TVA") to take any action shall take effect for 60 days following the date of issuance of the order. Within 60 days following the issuance by the Commission of any order under section 824i or of section 824j of this title requiring the TVA to enter into any contract for the sale or delivery of power, the Commission may on its own motion initiate, or upon petition of any aggrieved person shall initiate, an evidentiary hearing to determine whether or not such sale or delivery would result in violation of the third sentence of section 15d(a) of the Tennessee Valley Authority Act of 1933 (16 U.S.C. 831 n-4), hereinafter in this subsection referred to as the TVA Act [16 U.S.C.A. § 831 et seq.]

(2) Upon initiation of any evidentiary hearing under paragraph (1), the Commission shall give notice thereof to

any applicant who applied for and obtained the order from the Commission, to any electric utility or other entity subject to such order, and to the public, and shall promptly make the determination referred to in paragraph (1). Upon initiation of such hearing the Commission shall stay the effectiveness of the order under section 824i or 824j of this title until whichever of the following dates is applicable—

(A) the date on which there is a final determination (including any judicial review thereof under paragraph (3)) that no such violation would result from such order, or

(B) the date on which a specific authorization of the Congress (within the meaning of the third sentence of section 15d(a) of the TVA Act [16 U.S.C.A. § 831n-4(a)]) takes effect.

(3) Any determination under paragraph (1) shall be reviewable only in the appropriate court of the United States upon petition filed by any aggrieved person or municipality within 60 days after such determination, and such court shall have jurisdiction to grant appropriate relief. Any applicant who applied for and obtained the order under section 824i or 824j of this title, and any electric utility or other entity subject to such order shall have the right to intervene in any such proceeding in such court. Except for review by such court (and any appeal or other review by an appellate court of the United States), no court shall have jurisdiction to consider any action brought by any person to enjoin the carrying out of any order of the Commission under section 824i or section 824j of this title requiring the TVA to take any action on the grounds that such action requires a specific authorization of the Congress pursuant to the third sentence of section 15d(a) of the TVA Act [16 U.S.C.A. § 831n-4(a)].

SUBCHAPTER III—LICENSEES AND PUBLIC UTILITIES; PROCEDURAL AND ADMINISTRATIVE PROVISIONS

§ 825. Accounts and records

(a) Duty to keep

Every licensee and public utility shall make, keep, and preserve for such periods, such accounts, records of cost-accounting procedures, correspondence, memoranda, papers, books, and other records as the Commission may by rules and regulations prescribe as necessary or appropriate for purposes of the administration of this chapter, including accounts, records and memoranda of the generation, transmission, distribution, delivery, or sale of electric energy, the furnishing of services or facilities in connection therewith, and receipts and expenditures with respect to any of the foregoing: *Provided, however,* That nothing in this chapter shall relieve any public utility from keeping any accounts, memoranda, or records which such public utility may be required to keep by or under authority of the laws of any State. The Commission may prescribe a system of accounts to be kept by licensees and public utilities and may classify such licensees and public utilities and prescribe a system of accounts for each class. The Commission, after notice and opportunity for hearing, may determine by order the accounts in which particular outlays and receipts shall be entered, charged, or credited. The burden of proof to justify every accounting entry questioned by the Commission shall be on the person making, authorizing, or requiring such entry, and the Commission may suspend a charge or credit pending submission of satisfactory proof in support thereof.

(b) Access to and examination by Commission

The Commission shall at all times have access to and the right to inspect and examine all accounts, records, and

memoranda of licensees and public utilities, and it shall be the duty of such licensees and public utilities to furnish to the Commission, within such reasonable time as the Commission may order, any information with respect thereto which the Commission may by order require, including copies of maps, contracts, reports of engineers, and other data, records, and papers, and to grant to all agents of the Commission free access to its property and its accounts, records, and memoranda when requested so to do. No member, officer, or employee of the Commission shall divulge any fact or information which may come to his knowledge during the course of examination of books or other accounts, as hereinbefore provided, except insofar as he may be directed by the Commission or by a court.

(c) Controlling individual

The books, accounts, memoranda, and records of any person who controls, directly or indirectly, a licensee or public utility subject to the jurisdiction of the Commission, and of any other company controlled by such person, insofar as they relate to transactions with or the business of such licensee or public utility, shall be subject to examination on the order of the Commission.

§ 825a. Rates of depreciation; notice to State authorities before fixing

(a) The Commission may, after hearing, require licensees and public utilities to carry a proper and adequate depreciation account in accordance with such rules, regulations, and forms of account as the Commission may prescribe. The Commission may, from time to time, ascertain and determine, and by order fix, the proper and adequate rates of depreciation of the several classes of property of each licensee and public utility. Each licensee and public utility shall conform its depreciation accounts to the rates so ascertained, determined, and fixed. The licensees and public utilities subject to the jurisdiction of the Commission

shall not charge to operating expenses any depreciation charges on classes of property other than those prescribed by the Commission, or charge with respect to any class of property a percentage of depreciation other than that prescribed therefor by the Commission. No such licensee or public utility shall in any case include in any form under its operating or other expenses any depreciation or other charge or expenditure included elsewhere as a depreciation charge or otherwise under its operating or other expenses. Nothing in this section shall limit the power of a State commission to determine in the exercise of its jurisdiction, with respect to any public utility, the percentage rate of depreciation to be allowed, as to any class of property of such public utility, or the composite depreciation rate, for the purpose of determining rates or charges.

(b) The Commission, before prescribing any rules or requirements as to accounts, records, or memoranda, or as to depreciation rates, shall notify each State commission having jurisdiction with respect to any public utility involved, and shall give reasonable opportunity to each such commission to present its views, and shall receive and consider such views and recommendations.

§ 825b. Requirements applicable to agencies of United States

All agencies of the United States engaged in the generation and sale of electric energy for ultimate distribution to the public shall be subject, as to all facilities used for such generation and sale, and as to the electric energy sold by such agency, to the provisions of sections 825 and 825a of this title, so far as may be practicable, and shall comply with the provisions of such sections and with the rules and regulations of the Commission thereunder to the same extent as may be required in the case of a public utility.

§ 825c. Periodic and special reports; obstructing filing reports or keeping accounts, etc.

(a) Every licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this chapter. The Commission may prescribe the manner and form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies.

(b) It shall be unlawful for any person willfully to hinder, delay, or obstruct the making, filing, or keeping of any information, document, report, memorandum, record, or account required to be made, filed, or kept under this chapter or any rule, regulation, or order thereunder.

§ 825d. Officials dealing in securities

(a) Benefits; making or declaring dividends out of capital account

It shall be unlawful for any officer or director of any public utility to receive for his own benefit, directly or indirectly, any money or thing of value in respect of the

negotiation, hypothecation, or sale by such public utility of any security issued or to be issued by such public utility, or to share in any of the proceeds thereof, or to participate in the making or paying of any dividends of such public utility from any funds properly including in capital account.

(b) Interlocking directorates

After six months from August 26, 1935, it shall be unlawful for any person to hold the position of officer or director or more than one public utility or to hold the position of officer or director of a public utility and the position of officer or director of any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of a public utility, or officer or director of any company supplying electrical equipment to such public utility, unless the holding of such positions shall have been authorized by order of the Commission, upon due showing in form and manner prescribed by the Commission, that neither public nor private interests will be adversely affected thereby. The Commission shall not grant any such authorization in respect of such positions held on August 26, 1935, unless application for such authorization is filed with the Commission within sixty days after that date.

(c) Statement of prior positions; definitions

(1) On or before April 30 of each year, any person, who, during the calendar year preceding the filing date under this subsection, was an officer or director of a public utility and who held, during such calendar year, the position of officer, director, partner, appointee, or representative of any other entity listed in paragraph (2) shall file with the Commission, in such form and manner as the Commission shall by rule prescribe a written statement concerning such positions held by such person. Such statement shall be available to the public.

(2) The entities listed for purposes of paragraph (1) are as follows—

(A) any investment bank, bank holding company, foreign bank or subsidiary thereof doing business in the United States, insurance company, or any other organization primarily engaged in the business of providing financial services or credit, a mutual savings bank, or a savings and loan association;

(B) any company, firm, or organization which is authorized by law to underwrite or participate in the marketing of securities of a public utility;

(C) any company, firm, or organization which produces or supplies electrical equipment or coal, natural gas, oil, nuclear fuel, or other fuel for the use of any public utility;

(D) any company, firm, or organization which during any one of the 3 calendar years immediately preceding the filing date was one of the 20 purchasers of electric energy which purchased (for purposes other than for resale) one of the 20 largest annual amounts of electric energy sold by such public utility (or by any public utility which is part of the same holding company system) during any one of such three calendar years;

(E) any entity referred to in subsection (b) of this section; and

(F) any company, firm, or organization which is controlled by any company, firm, or organization referred to in this paragraph.

On or before January 31 of each calendar year, each public utility shall publish a list, pursuant to rules prescribed by the Commission, of the purchasers to which subparagraph (D) applies, for purposes of any filing under paragraph (1) of such calendar year.

(3) For purposes of this subsection—

(A) The term "public utility" includes any company which is a part of a holding company system which includes a registered holding company, unless no company in such system is an electric utility.

(B) The terms "holding company", "registered holding company", and "holding company system" have the same meaning as when used in the Public Utility Holding Company Act of 1935 [15 U.S.C.A. § 79 et seq.].

§ 825e. Complaints

Any person, State, municipality, or State commission complaining of anything done or omitted to be done by any licensee or public utility in contravention of the provisions of this chapter may apply to the Commission by petition which shall briefly state the facts, whereupon a statement of the complaint thus made shall be forwarded by the Commission to such licensee or public utility, who shall be called upon to satisfy the complaint or to answer the same in writing within a reasonable time to be specified by the Commission. If such licensee or public utility shall not satisfy the complaint within the time specified or there shall appear to be any reasonable ground for investigating such complaint, it shall be the duty of the Commission to investigate the matters complained of in such manner and by such means as it shall find proper.

§ 825f. Investigations by Commission

(a) Scope

The Commission may investigate any facts, conditions, practices, or matters which it may find necessary or proper in order to determine whether any person has violated or is about to violate any provision of this chapter or any rule, regulation, or order thereunder, or to aid in the enforcement of the provisions of this chapter or in prescrib-

ing rules or regulations thereunder, or in obtaining information to serve as a basis for recommending further legislation concerning the matters to which this chapter relates. The Commission may permit any person to file with it a statement in writing under oath or otherwise, as it shall determine, as to any or all facts and circumstances concerning a matter which may be the subject of investigation. The Commission, in its discretion, may publish or make available to State commissions information concerning any such subject.

(b) Attendance of witnesses and production of documents

For the purpose of any investigation or any other proceeding under this chapter, any member of the Commission, or any officer designated by it, is empowered to administer oaths and affirmations, subpena witnesses, compel their attendance, take evidence, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records which the Commission finds relevant or material to the inquiry. Such attendance of witnesses and the production of any such records may be required from any place in the United States at any designated place of hearing. Witnesses summoned by the Commission to appear before it shall be paid the same fees and mileage that are paid witnesses in the courts of the United States.

(c) Resort to courts of United States for failure to obey subpena; punishment

In case of contumacy by, or refusal to obey a subpena issued to, any person, the Commission may invoke the aid of any court of the United States within the jurisdiction of which such investigation or proceeding is carried on, or where such person resides or carries on business, in requiring the attendance and testimony of witnesses and the production of books, papers, correspondence, memo-

randa, contracts, agreements, and other records. Such court may issue an order requiring such person to appear before the Commission or member or officer designated by the Commission, there to produce records, if so ordered, or to give testimony touching the matter under investigation or in question; and any failure to obey such order of the court may be punished by such court as a contempt thereof. All process in any such case may be served in the judicial district whereof such person is an inhabitant or wherever he may be found or may be doing business. Any person who willfully shall fail or refuse to attend and testify or to answer any lawful inquiry or to produce books, papers, correspondence, memoranda, contracts, agreements, or other records, if in his or its power so to do, in obedience to the subpena of the Commission, shall be guilty of a misdemeanor and, upon conviction, shall be subject to a fine of not more than $1,000 or to imprisonment for a term of not more than one year, or both.

(d) Testimony by deposition

The testimony of any witness may be taken, at the instance of a party, in any proceeding or investigation pending before the Commission, by deposition, at any time after the proceeding is at issue. The Commission may also order testimony to be taken by deposition in any proceeding or investigation pending before it, at any stage of such proceeding or investigation. Such depositions may be taken before any person authorized to administer oaths not being of counsel or attorney to either of the parties, nor interested in the proceeding or investigation. Reasonable notice must first be given in writing by the party or his attorney proposing to take such deposition to the opposite party or his attorney of record, as either may be nearest, which notice shall state the name of the witness and the time and place of the taking of his deposition. Any person may be compelled to appear and depose, and to produce documentary evidence, in the same manner as

witnesses may be compelled to appear and testify and produce documentary evidence before the Commission, as hereinbefore provided. Such testimony shall be reduced to writing by the person taking the deposition, or under his direction, and shall, after it has been reduced to writing, be subscribed by the deponent.

(e) Deposition of witness in foreign country

If a witness whose testimony may be desired to be taken by deposition be in a foreign country, the deposition may be taken before an officer or person designated by the Commission, or agreed upon by the parties by stipulation in writing to be filed with the Commission. All depositions must be promptly filed with the Commission.

(f) Deposition fees

Witnesses whose depositions are taken as authorized in this chapter, and the person or officer taking the same, shall be entitled to the same fees as are paid for like services in the courts of the United States.

§ 825g. Hearings; rules of procedure

(a) Hearings under this chapter may be held before the Commission, any member or members thereof or any representative of the Commission designated by it, and appropriate records thereof shall be kept. In any proceeding before it, the Commission, in accordance with such rules and regulations as it may prescribe, may admit as a party any interested State, State commission, municipality, or any representative of interested consumers or security holders, or any competitor of a party to such proceeding, or any other person whose participation in the proceeding may be in the public interest.

(b) All hearings, investigations, and proceedings under this chapter shall be governed by rules of practice and procedure to be adopted by the Commission, and in the

conduct thereof the technical rules of evidence need not be applied. No informality in any hearing, investigation, or proceeding or in the manner of taking testimony shall invalidate any order, decision, rule, or regulation issued under the authority of this chapter.

§ 825h. Administrative powers of Commission; rules, regulations, and orders

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this chapter; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed. Unless a different date is specified therein, rules and regulations of the Commission shall be effective thirty days after publication in the manner which the Commission shall prescribe. Orders of the Commission shall be effective on the date and in the manner which the Commission shall prescribe. For the purposes of its rules and regulations, the Commission may classify persons and matters within its jurisdiction and prescribe different requirements for different classes of persons or matters. All rules and regulations of the Commission shall be filed with its secretary and shall be kept open in convenient form for public inspection and examination during reasonable business hours.

§ 825i. Appointment of officers and employees; compensation

The Commission is authorized to appoint and fix the compensation of such officers, attorneys, examiners, and experts as may be necessary for carrying out its functions under this chapter; and the Commission may, subject to civil-service laws, appoint such other officers and employ-

ees as are necessary for carrying out such functions and fix their salaries in accordance with chapter 51 and subchapter III of chapter 53 of Title 5.

§ 825j. Investigations relating to electric energy; reports to Congress

In order to secure information necessary or appropriate as a basis for recommending legislation, the Commission is authorized and directed to conduct investigations regarding the generation, transmission, distribution, and sale of electric energy, however produced, throughout the United States and its possessions, whether or not otherwise subject to the jurisdiction of the Commission, including the generation, transmission, distribution, and sale of electric energy by any agency, authority, or instrumentality of the United States, or of any State or municipality or other political subdivision of a State. It shall, so far as practicable, secure and keep current information regarding the ownership, operation, management, and control of all facilities for such generation, transmission, distribution, and sale; the capacity and output thereof and the relationship between the two; the cost of generation, transmission, and distribution; the rates, charges, and contracts in respect of the sale of electric energy and its service to residential, rural, commercial, and industrial consumers and other purchasers by private and public agencies; and the relation of any or all such facts to the development of navigation, industry, commerce, and the national defense. The Commission shall report to Congress the results of investigations made under authority of this section.

§ 825k. Publication and sale of reports

The Commission may provide for the publication of its reports and decisions in such form and manner as may be best adapted for public information and use, and is authorized to sell at reasonable prices copies of all maps, atlases, and reports as it may from time to time publish. Such reasonable prices may include the cost of compilation,

composition, and reproduction. The Commission is also authorized to make such charges as it deems reasonable for special statistical services and other special or periodic services. The amounts collected under this section shall be deposited in the Treasury to the credit of miscellaneous receipts. All printing for the Federal Power Commission making use of engraving, lithography, and photolithography, together with the plates for the same, shall be contracted for and performed under the direction of the Commission, under such limitations and conditions as the Joint Committee on Printing may from time to time prescribe, and all other printing for the Commission shall be done by the Public Printer under such limitations and conditions as the Joint Committee on Printing may from time to time prescribe. The entire work may be done at, or ordered through, the Government Printing Office whenever, in the judgment of the Joint Committee on Printing, the same would be to the interest of the Government: *Provided,* That when the exigencies of the public service so require, the Joint Committee on Printing may authorize the Commission to make immediate contracts for engraving, lithographing, and photolithographing, without advertisement for proposals: *Provided further,* That nothing contained in this chapter or any other Act shall prevent the Federal Power Commission from placing orders with other departments or establishments for engraving, lithographing, and photolithographing, in accordance with the provisions of sections 1535 and 1536 of Title 31, providing for interdepartmental work.

§ 825l. Review of orders

(a) Application for rehearing; time periods; modification of order

Any person, State, municipality, or State commission aggrieved by an order issued by the Commission in a proceeding under this chapter to which such person, State, municipality, or State commission is a party may apply

for a rehearing within thirty days after the issuance of such order. The application for rehearing shall set forth specifically the ground or grounds upon which such application is based. Upon such application the Commission shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing. Unless the Commission acts upon the application for rehearing within thirty days after it is filed, such application may be deemed to have been denied. No proceeding to review any order of the Commission shall be brought by any person unless such person shall have made application to the Commission for a rehearing thereon. Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b) of this section, the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.

(b) Judicial review

Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the United States Court of Appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be transmitted by the clerk of the court to any member of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of Title 28. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of

the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part. No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings which, if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside, in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States upon certiorari or certification as provided in section 1254 of Title 28.

(c) Stay of Commission's order

The filing of an application for rehearing under subsection (a) of this section shall not, unless specifically ordered by the Court, operate as a stay of the Commission's order. The commencement of proceedings under subsection (b) of this section shall not, unless specifically ordered by the court, operate as a stay of the Commission's order.

§ 825m. Enforcement provisions

(a) Enjoining and restraining violations

Whenever it shall appear to the Commission that any person is engaged or about to engage in any acts or practices which constitute or will constitute a violation of the provisions of this chapter, or of any rule, regulation, or order thereunder, it may in its discretion bring an action in the proper District Court of the United States or the United States courts of any Territory or other place subject to the jurisdiction of the United States, to enjoin such acts or practices and to enforce compliance with this chapter or any rule, regulation, or order thereunder, and upon a proper showing a permanent or temporary injunction or decree or restraining order shall be granted without bond. The Commission may transmit such evidence as may be available concerning such acts or practices to the Attorney General, who, in his discretion, may institute the necessary criminal proceedings under this chapter.

(b) Writs of mandamus

Upon application of the Commission the district courts of the United States and the United States courts of any Territory or other place subject to the jurisdiction of the United States shall have jurisdiction to issue writs of mandamus commanding any person to comply with the provisions of this chapter or any rule, regulation, or order of the Commission thereunder.

(c) Employment of attorneys

The Commission may employ such attorneys as it finds necessary for proper legal aid and service of the Commission or its members in the conduct of their work, or for proper representation of the public interests in investigations made by it or cases or proceedings pending before it, whether at the Commission's own instance or upon complaint, or to appear for or represent the Commission

in any case in court; and the expenses of such employment shall be paid out of the appropriation for the Commission.

§ 825n. Forfeiture for violations; recovery

(a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this chapter or any rule or regulation of the Commission thereunder, to submit any information or document required by the Commission in the course of an investigation conducted under this chapter, or to appear by an officer or agent at any hearing or investigation in response to a subpena issued under this chapter, shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing. The imposition or payment of any such forfeiture shall not bar or affect any penalty prescribed in this chapter but such forfeiture shall be in addition to any such penalty.

(b) The forfeitures provided for in this chapter shall be payable into the Treasury of the United States and shall be recoverable in a civil suit in the name of the United States, brought in the district where the person is an inhabitant or has his principal place of business, or if a licensee or public utility, in any district in which such licensee or public utility transacts business. It shall be the duty of the various United States attorneys, under the direction of the Attorney General of the United States, to prosecute for the recovery of forfeitures under this chapter. The costs and expenses of such prosecution shall be paid from the appropriations for the expenses of the courts of the United States.

§ 825o. Penalties

(a) Any person who willfully and knowingly does or causes or suffers to be done any act, matter, or thing in this chapter prohibited or declared to be unlawful, or who willfully and knowingly omits or fails to do any act, matter,

or thing in this chapter required to be done, or willfully and knowingly causes or suffers such omission or failure, shall, upon conviction thereof, be punished by a fine of not more than $5,000 or by imprisonment for not more than two years, or both.

(b) Any person who willfully and knowingly violates any rule, regulation, restriction, condition, or order made or imposed by the Commission under authority of this chapter, or any rule or regulation imposed by the Secretary of the Army under authority of subchapter I of this chapter shall, in addition to any other penalties provided by law, be punished upon conviction thereof by a fine of not exceeding $500 for each and every day during which such offense occurs.

§ 825p. Jurisdiction of offenses; enforcement of liabilities and duties

The District Courts of the United States, and the United States courts of any Territory or other place subject to the jurisdiction of the United States shall have exclusive jurisdiction of violations of this chapter or the rules, regulations, and orders thereunder, and of all suits in equity and actions at law brought to enforce any liability or duty created by, or to enjoin any violation of, this chapter or any rule, regulation, or order thereunder. Any criminal proceeding shall be brought in the district wherein any act or transaction constituting the violation occurred. Any suit or action to enforce any liability or duty created by, or to enjoin any violation of, this chapter or any rule, regulation, or order thereunder may be brought in any such district or in the district wherein the defendant is an inhabitant, and process in such cases may be served wherever the defendant may be found. Judgments and decrees so rendered shall be subject to review as provided in sections 1254, 1291, and 1292 of Title 28. No costs shall

be assessed against the Commission in any judicial proceeding by or against the Commission under this chapter.

§ 825q. Conflict of jurisdiction

If, with respect to the issue, sale, or guaranty of a security, or assumption of obligation or liability in respect of a security, the method of keeping accounts, the filing of reports, or the acquisition or disposition of any security, capital assets, facilities, or any other subject matter, any person is subject both to a requirement of the Public Utility Holding Company Act of 1935 [15 U.S.C.A. § 79 et seq.] or of a rule, regulation, or order thereunder and to a requirement of this chapter or of a rule, regulation, or order thereunder, the requirement of the Public Utility Holding Company Act of 1935 shall apply to such person, and such person shall not be subject to the requirement of this chapter, or of any rule, regulation, or order thereunder, with respect to the same subject matter, unless the Securities and Exchange Commission has exempted such person from such requirement of the Public Utility Holding Company Act of 1935, in which case the requirements of this chapter shall apply to such person.

§ 825q-1. Office of Public Participation

(a)(1) There shall be an office in the Commission to be known as the Office of Public Participation (hereinafter in this section referred to as the "Office").

(2)(A) The Office shall be administered by a Director. The Director shall be appointed by the Chairman with the approval of the Commission. The Director may be removed during his term of office by the Chairman, with the approval of the Commission, only for inefficiency, neglect of duty, or malfeasance in office.

(B) The term of office of the Director shall be 4 years. The Director shall be responsible for the discharge of the functions and duties of the Office. He shall be appointed and compensated at a rate not in excess of the maximum

rate prescribed for GS-18 of the General Schedule under section 5332 of Title 5.

(3) The Director may appoint, and assign the duties of, employees of such Office, and with the concurrence of the Commission he may fix the compensation of such employees and procure temporary and intermittent services to the same extent as is authorized under section 3109 of Title 5.

(b)(1) The Director shall coordinate assistance to the public with respect to authorities exercised by the Commission. The Director shall also coordinate assistance available to persons intervening or participating or proposing to intervene or participate in proceedings before the Commission.

(2) The Commission may, under rules promulgated by it, provide compensation for reasonable attorney's fees, expert witness fees, and other costs of intervening or participating in any proceeding before the Commission to any person whose intervention or participation substantially contributed to the approval, in whole or in part, of a position advocated by such person. Such compensation may be paid only if the Commission has determined that—

(A) the proceeding is significant, and

(B) such person's intervention or participation in such proceeding without receipt of compensation constitutes a significant financial hardship to him.

(3) Nothing in this subsection affects or restricts any rights of any intervenor or participant under any other applicable law or rule of law.

(4) There are authorized to be appropriated to the Secretary of Energy to be used by the Office for purposes of compensation of persons under the provisions of this subsection not to exceed $500,000 for the fiscal year 1978, not to exceed $2,000,000 for the fiscal year 1979, not to

exceed $2,200,000 for the fiscal year 1980, and not to exceed $2,400,000 for the fiscal year 1981.

§ 825r. Separability of provisions

If any provision of this chapter, or the application of such provision to any person or circumstance, shall be held invalid, the remainder of the chapter, and the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

APPENDIX G

§ 79a. Necessity for control of holding companies

Interstate nature of holding companies

(a) Public-utility holding companies and their subsidiary companies are affected with a national public interest in that, among other things, (1) their securities are widely marketed and distributed by means of the mails and instrumentalities of interstate commerce and are sold to a large number of investors in different States; (2) their service, sales, construction, and other contracts and arrangements are often made and performed by means of the mails and instrumentalities of interstate commerce; (3) their subsidiary public-utility companies often sell and transport gas and electric energy by the use of means and instrumentalities of interstate commerce; (4) their practices in respect of and control over subsidiary companies often materially affect the interstate commerce in which those companies engage; (5) their activities extending over many States are not susceptible of effective control by any State and make difficult, if not impossible, effective State regulation of public-utility companies.

Protection of investors and interests of consumers

(b) Upon the basis of facts disclosed by the reports of the Federal Trade Commission made pursuant to S.Res. 83 (Seventieth Congress, first session), the reports of the Committee on Interstate and Foreign Commerce, House of Representatives, made pursuant to H.Res. 59 (Seventy-second Congress, first session) and H.J.Res. 572 (Seventy-second Congress, second session) and otherwise disclosed and ascertained, it is declared that the national public interest, the interest of investors in the securities of holding companies and their subsidiary companies and affiliates, and the interest of consumers of electric energy and nat-

ural and manufactured gas, are or may be adversely affected—

(1) when such investors cannot obtain the information necessary to appraise the financial position or earning power of the issuers, because of the absence of uniform standard accounts; when such securities are issued without the approval or consent of the States having jurisdiction over subsidiary public-utility companies; when such securities are issued upon the basis of fictitious or unsound asset values having no fair relation to the sums invested in or the earning capacity of the properties and upon the basis of paper profits from intercompany transactions, or in anticipation of excessive revenues from subsidiary public-utility companies; when such securities are issued by a subsidiary public-utility company under circumstances which subject such company to the burden of supporting an overcapitalized structure and tend to prevent voluntary rate reductions;

(2) when subsidiary public-utility companies are subjected to excessive charges for services, construction work, equipment, and materials, or enter into transactions in which evils result from an absence of arm's-length bargaining or from restraint of free and independent competition; when service, management, construction, and other contracts involve the allocation of charges among subsidiary public-utility companies in different States so as to present problems of regulation which cannot be dealt with effectively by the States;

(3) when control of subsidiary public-utility companies affects the accounting practices and rate, dividend, and other policies of such companies so as to complicate and obstruct State regulation of such companies, or when control of such companies is exerted through disproportionately small investment;

(4) when the growth and extension of holding companies bears no relation to economy of management and operation or the integration and coordination of related operating properties; or

(5) when in any other respect there is lack of economy of management and operation of public-utility companies or lack of efficiency and adequacy of service rendered by such companies, or lack of effective public regulation, or lack of economies in the raising of capital.

Declaration of policy of chapter

(c) When abuses of the character above enumerated become persistent and wide-spread the holding company becomes an agency which, unless regulated, is injurious to investors, consumers, and the general public; and it is declared to be the policy of this chapter, in accordance with which policy all the provisions of this chapter shall be interpreted, to meet the problems and eliminate the evils as enumerated in this section, connected with public-utility holding companies which are engaged in interstate commerce or in activities which directly affect or burden interstate commerce; and for the purpose of effectuating such policy to compel the simplification of public-utility holding-company systems and the elimination therefrom of properties detrimental to the proper functioning of such systems, and to provide as soon as practicable for the elimination of public-utility holding companies except as otherwise expressly provided in this chapter.

§ 79b. Definitions; application of chapter

Definitions

(a) When used in this chapter, unless the context otherwise requires—

(1) "Person" means an individual or company.

(2) "Company" means a corporation, a partnership, an association, a joint-stock company, a business trust, or an organized group of persons, whether incorporated or not; or any receiver, trustee, or other liquidating agent of any of the foregoing in his capacity as such.

(3) "Electric utility company" means any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale, other than sale to tenants or employees of the company operating such facilities for their own use and not for resale. The Commission, upon application, shall by order declare a company operating any such facilities not to be an electric utility company if the Commission finds that (A) such company is primarily engaged in one or more businesses other than the business of an electric utility company, and by reason of the small amount of electric energy sold by such company it is not necessary in the public interest or for the protection of investors or consumers that such company be considered an electric utility company for the purposes of this chapter, or (B) such company is one operating within a single State, and substantially all of its outstanding securities are owned directly or indirectly by another company to which such operating company sells or furnishes electric energy which it generates; such other company uses and does not resell such electric energy, is engaged primarily in manufacturing (other than the manufacturing of electric energy or gas) and is not controlled by any other company; and by reason of the small amount of electric energy sold or furnished by such operating company to other persons it is not necessary in the public interest or for the protection of investors or consumers that it be considered an electric utility company for the purposes of this chapter. The filing of an application hereunder in good faith

shall exempt such company (and the owner of the facilities operated by such company) from the application of this paragraph until the Commission has acted upon such application. As a condition to the entry of any such order, and as a part thereof, the Commission may require application to be made periodically for a renewal of such order, and may require the filing of such periodic or special reports regarding the business of the company as the Commission may find necessary or appropriate to insure that such company continues to be entitled to such exemption during the period for which such order is effective. The Commission, upon its own motion or upon application, shall revoke such order whenever it finds that the conditions specified in clause (A) or (B) of this paragraph are not satisfied in the case of such company. Any action of the Commission under the preceding sentence shall be by order. Application under this paragraph may be made by the company in respect of which the order is to be issued or by the owner of the facilities operated by such company. Any order issued under this paragraph shall apply equally to such company and such owner. The Commission may by rules or regulations conditionally or unconditionally provide that any specified class or classes of companies which it determines to satisfy the conditions specified in clause (A) or (B) of this paragraph, and the owners of the facilities operated by such companies, shall not be deemed electric utility companies within the meaning of this paragraph.

(4) "Gas utility company" means any company which owns or operates facilities used for the distribution at retail (other than distribution only in enclosed portable containers, or distribution to tenants or employees of the company operating such facilities for their own use and not for resale) of natural or manufactured gas for heat, light, or power. The Commission,

upon application, shall by order declare a company operating any such facilities not to be a gas utility company if the Commission finds that (A) such company is primarily engaged in one or more businesses other than the business of a gas utility company, and (B) by reason of the small amount of natural or manufactured gas distributed at retail by such company it is not necessary in the public interest or for the protection of investors or consumers that such company be considered a gas utility company for the purposes of this chapter. The filing of an application hereunder in good faith shall exempt such company (and the owner of the facilities operated by such company) from the application of this paragraph until the Commission has acted upon such application. As a condition to the entry of any such order, and as a part thereof, the Commission may require application to be made periodically for a renewal of such order, and may require the filing of such periodic or special reports regarding the business of the company as the Commission may find necessary or appropriate to insure that such company continues to be entitled to such exemption during the period for which such order is effective. The Commission, upon its own motion or upon application, shall revoke such order whenever it finds that the conditions specified in clauses (A) and (B) of this paragraph are not satisfied in the case of such company. Any action of the Commission under the preceding sentence shall be by order. Application under this paragraph may be made by the company in respect of which the order is to be issued or by the owner of the facilities operated by such company. Any order issued under this paragraph shall apply equally to such company and such owner. The Commission may by rules or regulations conditionally or unconditionally provide that any specified class or classes of companies which it determines to satisfy

the conditions specified in clauses (A) and (B) of this paragraph, and the owners of the facilities operated by such companies, shall not be deemed gas utility companies within the meaning of this paragraph.

(5) "Public-utility company" means an electric utility company or a gas utility company.

(6) "Commission" means the Securities and Exchange Commission.

(7) "Holding company" means—

(A) any company which directly or indirectly owns, controls. or holds with power to vote, 10 per centum or more of the outstanding voting securities of a public-utility company or of a company which is a holding company by virtue of this clause or clause (B) of this paragraph, unless the Commission, as hereinafter provided, by order declares such company not to be a holding company; and

(B) any person which the Commission determines, after notice and opportunity for hearing, directly or indirectly to exercise (either alone or pursuant to an arrangement or understanding with one or more other persons) such a controlling influence over the management or policies of any public-utility or holding company as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that such person be subject to the obligations, duties, and liabilities imposed in this chapter upon holding companies.

The Commission, upon application, shall by order declare that a company is not a holding company under clause (A) of this paragraph if the Commission finds that the applicant (i) does not, either alone or pursuant to an arrangement or understanding with one or more other persons, directly or indirectly control a public-utility or holding company either through one

or more intermediary persons or by any means or device whatsoever, (ii) is not an intermediary company through which such control is exercised, and (iii) does not, directly or indirectly, exercise (either alone or pursuant to an arrangement or understanding with one or more other persons) such a controlling influence over the management or policies of any public-utility or holding company as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the applicant be subject to the obligations, duties, and liabilities imposed in this chapter upon holding companies. The filing of an application hereunder in good faith by a company other than a registered holding company shall exempt the applicant from any obligation, duty, or liability imposed in this chapter upon the applicant as a holding company, until the Commission has acted upon such application. Within a reasonable time after the receipt of any application hereunder, the Commission shall enter an order granting, or, after notice and opportunity for hearing, denying or otherwise disposing of, such application. As a condition to the entry of any order granting such application and as a part of any such order, the Commission may require the applicant to apply periodically for a renewal of such order and to do or refrain from doing such acts or things, in respect of exercise of voting rights, control over proxies, designation of officers and directors, existence of interlocking officers, directors and other relationships, and submission of periodic or special reports regarding affiliations or intercorporate relationships of the applicant, as the Commission may find necessary or appropriate to ensure that in the case of the applicant the conditions specified in clauses (i), (ii), and (iii) of this paragraph are satisfied during the period for which such order is effective. The Commission, upon its own motion or upon application of

the company affected, shall revoke the order declaring such company not to be a holding company whenever in its judgment any condition specified in clauses (i), (ii), or (iii) of this paragraph is not satisfied in the case of such company, or modify the terms of such order whenever in its judgment such modification is necessary to ensure that in the case of such company the conditions specified in clauses (i), (ii), and (iii) of this paragraph are satisfied during the period for which such order is effective. Any action of the Commission under the preceding sentence shall be by order.

(8) "Subsidiary company" of a specified holding company means—

(A) any company 10 per centum or more of the outstanding voting securities of which are directly or indirectly owned, controlled, or held with power to vote, by such holding company (or by a company that is a subsidiary company of such holding company by virtue of this clause or clause (B) of this paragraph), unless the Commission, as hereinafter provided, by order declares such company not to be a subsidiary company of such holding company; and

(B) any person the management or policies of which the Commission, after notice and opportunity for hearing, determines to be subject to a controlling influence, directly or indirectly, by such holding company (either alone or pursuant to an arrangement or understanding with one or more other persons) so as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that such person be subject to the obligations, duties, and liabilities imposed in this chapter upon subsidiary companies of holding companies.

The Commission, upon application, shall by order declare that a company is not a subsidiary company of a specified holding company under clause (A) of this paragraph if the Commission finds that (i) the applicant is not controlled, directly or indirectly, by such holding company (either alone or pursuant to an arrangement or understanding with one or more other persons) either through one or more intermediary persons or by any means or device whatsoever, (ii) the applicant is not an intermediary company through which such control of another company is exercised, and (iii) the management or policies of the applicant are not subject to a controlling influence, directly or indirectly, by such holding company (either alone or pursuant to an arrangement or understanding with one or more other persons) so as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the applicant be subject to the obligations, duties, and liabilities imposed in this chapter upon subsidiary companies of holding companies. The filing of an application hereunder in good faith shall exempt the applicant from any obligation, duty, or liability imposed in this chapter upon the applicant as a subsidiary company of such specified holding company until the Commission has acted upon such application. Within a reasonable time after the receipt of any application hereunder, the Commission shall enter an order granting, or, after notice and opportunity for hearing, denying or otherwise disposing of, such application. As a condition to the entry of, and as a part of, any order granting such application, the Commission may require the applicant to apply periodically for a renewal of such order and to file such periodic or special reports regarding the affiliations or intercorporate relationships of the applicant as the Commission may find necessary or appropriate to enable it to determine whether in

the case of the applicant the conditions specified in clauses (i), (ii), and (iii) of this paragraph are satisfied during the period for which such order is effective. The Commission, upon its own motion or upon application, shall revoke the order declaring such company not to be a subsidiary company whenever in its judgment any condition specified in clauses (i), (ii), or (iii) of this paragraph is not satisfied in the case of such company, or modify the terms of such order whenever in its judgment such modification is necessary to ensure that in the case of such company the conditions specified in clauses (i), (ii), and (iii) of this paragraph are satisfied during the period for which such order is effective. Any action of the Commission under the preceding sentence shall be by order. Any application under this paragraph may be made by the holding company or the company in respect of which the order is to be entered, but as used in this paragraph the term "applicant" means only the company in respect of which the order is to be entered.

(9) "Holding-company system" means any holding company, together with all its subsidiary companies, and all mutual service companies (as defined in paragraph (13) of this subsection) of which such holding company or any subsidiary company thereof is a member company (as defined in paragraph (14) of this subsection).

(10) "Associate company" of a company means any company in the same holding-company system with such company.

(11) "Affiliate" of a specified company means—

(A) any person that directly or indirectly owns, controls, or holds with power to vote, 5 per centum or more of the outstanding voting securities of such specified company;

(B) any company 5 per centum or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by such specified company;

(C) any individual who is an officer or director of such specified company, or of any company which is an affiliate thereof under clause (A) of this paragraph; and

(D) any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to such specified company that there is liable to be such an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that such person be subject to the obligations, duties, and liabilities imposed in this chapter upon affiliates of a company.

(12) "Registered holding company" means a person whose registration is in effect under section 79e of this title.

(13) "Mutual service company" means a company approved as a mutual service company under section 79m of this title.

(14) "Member company" means a company which is a member of an association or group of companies mutually served by a mutual service company.

(15) "Director" means any director of a corporation or any individual who performs similar functions in respect of any company.

(16) "Security" means any note, draft, stock, treasury stock, bond, debenture, certificate of interest or participation in any profit-sharing agreement or in any

oil, gas, other mineral royalty or lease, any collateral-trust certificate, preorganization certificate or subscription, transferable share, investment contract, voting-trust certificate, certificate of deposit for a security, receiver's or trustee's certificate, or, in general, any instrument commonly known as a "security"; or any certificate of interest or participation in, temporary or interim certificate for, receipt for, guaranty of, assumption of liability on, or warrant or right to subscribe to or purchase, any of the foregoing.

(17) "Voting security" means any security presently entitling the owner or holder thereof to vote in the direction of management of the affairs of a company, or any security issued under or pursuant to any trust, agreement, or arrangement whereby a trustee or trustee or agent or agents for the owner or holder of such security are presently entitled to vote in the direction or management of the affairs of a company; and a specified per centum of the outstanding voting securities of a company means such amount of the outstanding voting securities of such company as entitles the holder or holders thereof to cast said specified per centum of the aggregate votes which the holders of all outstanding voting securities of such company are entitled to cast in the direction or management of the affairs of such company.

(18) "Utility assets" means the facilities, in place, of any electric utility company or gas utility company for the production, transmission, transportation, or distribution of electric energy or natural or manufactured gas.

(19) "Service contract" means any contract, agreement, or understanding whereby a person undertakes to sell or furnish, for a charge, any managerial, financial, legal, engineering, purchasing, marketing, au-

diting, statistical, advertising, publicity, tax, research, or any other service, information, or data.

(20) "Sales contract" means any contract, agreement, or understanding whereby a person undertakes to sell, lease, or furnish, for a charge, any goods, equipment, materials, supplies, appliances, or similar property. As used in this paragraph the term "property" does not include electric energy or natural or manufactured gas.

(21) "Construction contract" means any contract, agreement, or understanding for the construction, extension, improvement, maintenance, or repair of the facilities or any part thereof of a company for a charge.

(22) "Buy", "acquire", "acquisition", or "purchase" includes any purchase, acquisition by lease, exchange, merger, consolidation, or other acquisition.

(23) "Sale" or "sell" includes any sale, disposition by lease, exchange or pledge, or other disposition.

(24) "State" means any State of the United States or the District of Columbia.

(25) "United States", when used in a geographical sense, means the States.

(26) "State commission" means any commission, board, agency, or officer, by whatever name designated, of a State, municipality, or other political subdivision of a State which under the law of such State has jurisdiction to regulate public-utility companies.

(27) "State securities comission" means any commission, board, agency, or officer, by whatever name designated, other than a State commission as defined in paragraph (26) of this subsection, which under the law of a State has jurisdiction to regulate, approve, or control the issue or sale of a security by a company.

(28) "Interstate commerce" means trade, commerce, transportation, transmission, or communication among the several States or between any State and any place outside thereof.

(29) "Integrated public-utility system" means—

(A) As applied to electric utility companies, a system consisting of one or more units of generating plants and/or transmission lines and/or distributing facilities, whose utility assets, whether owned by one or more electric utility companies, are physically interconnected or capable of physical interconnection and which under normal conditions may be economically operated as a single interconnected and coordinated system confined in its operations to a single area or region, in one or more States, not so large as to impair (considering the state of the art and the area or region affected) the advantages of localized management, efficient operation, and the effectiveness of regulation; and

(B) As applied to gas utility companies, a system consisting of one or more gas utility companies which are so located and related that substantial economies may be effectuated by being operated as a single coordinated system confined in its operations to a single area or region, in one or more States, not so large as to impair (considering the state of the art and the area or region affected) the advantages of localized management, efficient operation, and the effectiveness of regulation: *Provided,* That gas utility companies deriving natural gas from a common source of supply may be deemed to be included in a single area or region.

Order of Commission essential to status as "holding company", "subsidiary company", or "affiliate"

(b) No person shall be deemed to be a holding company under clause (B) of paragraph (7) of subsection (a) of this

section, or a subsidiary company under clause (B) of paragraph (8) of such subsection, or an affiliate under clause (D) of paragraph (11) of such subsection, unless the Commission, after appropriate notice and opportunity for hearing, has issued an order declaring such person to be a holding company, a subsidiary company, or an affiliate, or declaring a class of which such person is a member to be affiliates. Such an order shall not become effective for at least thirty days after the mailing of a copy thereof to the person thereby declared to be a holding company, subsidiary company, or affiliate; or, in the case of determination of affiliates by classes, until at least thirty days after appropriate publication thereof in such manner as the Commission shall determine. Whenever the Commission, on its own motion or upon application by the person declared to be a holding company, subsidiary company, or affiliate, finds that the circumstances which gave rise to the issuance of any such order no longer exist, the Commission shall by order revoke such order.

Chapter inapplicable to United States, States, or their governmental agencies

(c) No provision in this chapter shall apply to, or be deemed to include, the United States, a State, or any political subdivision of a State, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned directly or indirectly by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

§ 79h. Acquiring interest in electric and gas companies serving same territory

Whenever a State law prohibits, or requires approval or authorization of, the ownership or operation by a single company of the utility assets of an electric utility company

and a gas utility company serving substantially the same territory, it shall be unlawful for a registered holding company, or any subsidiary company thereof, by use of the mails or any means or instrumentality of interstate commerce, or otherwise—

(1) to take any step, without the express approval of the State commission of such State, which results in its having a direct or indirect interest in an electric utility company and a gas utility company serving substantially the same territory; or

(2) if it already has any such interest, to acquire, without the express approval of the State commission, any direct or indirect interest in an electric utility company or gas utility company serving substantially the same territory as that served by such companies in which it already has an interest.

§ 79k. Simplification of holding company systems

Examination by Commission with view to simplification

(a) It shall be the duty of the Commission to examine the corporate structure of every registered holding company and subsidiary company thereof, the relationships among the companies in the holding-company system, of every such company and the character of the interests thereof and the properties owned or controlled thereby to determine the extent to which the corporate structure of such holding-company system and the companies therein may be simplified, unnecessary complexities therein eliminated, voting power fairly and equitably distributed among the holders of securities thereof, and the properties and business thereof confined to those necessary or appropriate to the operations of an integrated public-utility system.

Limitations on operations of holding company systems

(b) It shall be the duty of the Commission, as soon as practicable after January 1, 1938:

(1) To require by order, after notice and opportunity for hearing, that each registered holding company, and each subsidiary company thereof, shall take such action as the Commission shall find necessary to limit the operations of the holding-company system of which such company is a part to a single integrated public-utility system, and to such other businesses as are reasonably incidental, or economically necessary or appropriate to the operations of such integrated public-utility system: *Provided, however*, That the Commission shall permit a registered holding company to continue to control one or more additional integrated public-utility systems, if, after notice and opportunity for hearing, it finds that—

(A) Each of such additional systems cannot be operated as an independent system without the loss of substantial economies which can be secured by the retention of control by such holding company of such systems;

(B) All of such additional systems are located in one State, or in adjoining States, or in a contiguous foreign country; and

(C) The continued combinations of such systems under the control of such holding company is not so large (considering the state of the art and the area or region affected) as to impair the advantages of localized management, efficient operation, or the effectiveness of regulation.

The Commission may permit as reasonably incidental, or economically necessary or appropriate to the operations of one or more integrated public-utility systems the retention of an interest in any business (other

than the business of a public-utility company as such) which the Commission shall find necessary or appropriate in the public interest or for the protection of investors or consumers and not detrimental to the proper functioning of such system or systems.

(2) To require by order, after notice and opportunity for hearing, that each registered holding company, and each subsidiary company thereof, shall take such steps as the Commission shall find necessary to ensure that the corporate structure or continued existence of any company in the holding-company system does not unduly or unnecessarily complicate the structure, or unfairly or inequitably distribute voting power among security holders of such holding-company system. In carrying out the provisions of this paragraph the Commission shall require each registered holding company (and any company in the same holding-company system with such holding company) to take such action as the Commission shall find necessary in order that such holding company shall cease to be a holding company with respect to each of its subsidiary companies which itself has a subsidiary company which is a holding company. Except for the purpose of fairly and equitably distributing voting power among the security holders of such company, nothing in this paragraph shall authorize the Commission to require any change in the corporate structure or existence of any company which is not a holding company, or of any company whose principal business is that of a public-utility company.

The Commission may by order revoke or modify any order previously made under this subsection, if, after notice and opportunity for hearing, it finds that the conditions upon which the order was predicated do not exist. Any order made under this subsection shall be subject to judicial review as provided in section 79x of this title.

Time for compliance with order limiting operations

(c) Any order under subsection (b) of this section shall be complied with within one year from the date of such order; but the Commission shall, upon a showing (made before or after the entry of such order) that the applicant has been or will be unable in the exercise of due diligence to comply with such order within such time, extend such time for an additional period not exceeding one year if it finds such extension necessary or appropriate in the public interest or for the protection of investors or consumers.

Court enforcement of order for simplification; appointment of trustee; disposition of assets; reorganization plan

(d) The Commission may apply to a court, in accordance with the provisions of subsection (f) of section 79r of this title, to enforce compliance with any order issued under subsection (b) of this section. In any such proceeding, the court as a court of equity may, to such extent as it deems necessary for purposes of enforcement of such order, take exclusive, jurisdiction and possession of the company or companies and the assets thereof, wherever located; and the court shall have jurisdiction, in any such proceeding, to appoint a trustee, and the court may constitute and appoint the Commission as sole trustee, to hold or administer under the direction of the court the assets so possessed. In any proceeding for the enforcement of an order of the Commission issued under subsection (b) of this section, the trustee with the approval of the court shall have power to dispose of any or all of such assets and, subject to such terms and conditions as the court may prescribe, may make such disposition in accordance with a fair and equitable reorganization plan which shall have been approved by the Commission after opportunity for hearing. Such reorganization plan may be proposed in the first instance by the Commission, or, subject to such rules

and regulations as the Commission may deem necessary or appropriate in the public interest or for the protection of investors, by any person having a bona fide interest (as defined by the rules and regulations of the Commission) in the reorganization.

Submission by company of plan for simplification; court enforcement of order of approval; appointment of trustee

(e) In accordance with such rules and regulations or order as the Commission may deem necessary or appropriate in the public interest or for the protection of investors or consumers, any registered holding company or any subsidiary company of a registered holding company may, at any time after January 1, 1936, submit a plan to the Commission for the divestment of control, securities, or other assets, or for other action by such company or any subsidiary company thereof for the purpose of enabling such company or any subsidiary company thereof to comply with the provisions of subsection (b) of this section. If, after notice and opportunity for hearing, the Commission shall find such plan, as submitted or as modified, necessary to effectuate the provisions of subsection (b) of this section and fair and equitable to the persons affected by such plan, the Commission shall make an order approving such plan; and the Commission, at the request of the company, may apply to a court in accordance with the provisions of subsection (f) of section 79r of this title, to enforce and carry out the terms and provisions of such plan. If, upon such application, the court, after notice and opportunity for hearing, shall approve such plan as fair and equitable and as appropriate to effectuate the provisions of this section, the court as a court of equity may, to such extent as it deems necessary for the purpose of carrying out the terms and provisions of such plan, take exclusive jurisdiction and possession of the company or companies and the assets thereof, wherever located; and the court shall have juris-

diction to appoint a trustee, and the court may constitute and appoint the Commission as sole trustee, to hold or administer, under the direction of the court and in accordance with the plan therefore approved by the court and the Commission, the assets so possessed.

Commission as trustee; submission of reorganization plan by Commission or interested party

(f) In any proceeding in a court of the United States, whether under this section or otherwise, in which a receiver or trustee is appointed for any registered holding company, or any subsidiary company thereof, the court may constitute and appoint the Commission as sole trustee or receiver, subject to the directions and orders of the court, whether or not a trustee or receiver shall theretofore have been appointed, and in any such proceeding the court shall not appoint any person other than the Commission as trustee or receiver without notifying the Commission and giving it an opportunity to be heard before making any such appointment. In no proceeding under this section or otherwise shall the Commission be appointed as trustee or receiver without its express consent. In any such proceeding a reorganization plan for a registered holding company or any subsidiary company thereof shall not become effective unless such plan shall have been approved by the Commission after opportunity for hearing prior to its submission to the court. Notwithstanding any other provision of law, any such reorganization plan may be proposed in the first instance by the Commission or, subject to such rules and regulations as the Commission may deem necessary or appropriate in the public interest or for the protection of investors, by any person having a bona fide interest (as defined by the rules and regulations of the Commission) in the reorganization. The Commission may, by such rules and regulations or order as it may deem necessary or appropriate in the public interest or for the protection of investors or consumers, require that

any or all fees, expenses, and remuneration, to whomsoever paid, in connection with any reorganization, dissolution, liquidation, case under Title 11, or receivership of a registered holding company or subsidiary company thereof, in any such proceeding, shall be subject to approval by the Commission.

Solicitation of proxies, powers of attorney, etc., in respect of reorganization plan

(g) It shall be unlawful for any person to solicit or permit the use of his or its name to solicit, by use of the mails or any means or instrumentality of interstate commerce, or otherwise, any proxy, consent, authorization, power of attorney, deposit, or dissent in respect of any reorganization plan of a registered holding company or any subsidiary company thereof under this section, or otherwise, or in respect of any plan under this section for the divestment of control, securities, or other assets, or for the dissolution of any registered holding company or any subsidiary company thereof, unless—

(1) the plan has been proposed by the Commission, or the plan and such information regarding it and its sponsors as the Commission may deem necessary or appropriate in the public interest or for the protection of investors or consumers has been submitted to the Commission by a person having a bona fide interest (as defined by the rules and regulations of the Commission) in such reorganization;

(2) each such solicitation is accompanied or preceded by a copy of a report on the plan which shall be made by the Commission after an opportunity for a hearing on the plan and other plans submitted to it, or by an abstract of such report made or approved by the Commission; and

(3) each such solicitation is made not in contravention of such rules and regulations or orders as the

Commission may deem necessary or appropriate in the public interest or for the protection of investors or consumers.

Nothing in this subsection or the rules and regulations thereunder shall prevent any person from appearing before the Commission or any court through an attorney or proxy.